



**Potential impact of the Mineral and Petroleum Resources  
Development Amendment Bill on investment in South  
Africa's upstream oil and gas industry**

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## ABSTRACT

The Mineral and Petroleum Resources Development Amendment Bill has drawn criticism from industry experts and the press. There are a number of amendments that could be damaging to future investment in South Africa's upstream oil and gas industry.

This study examines the key changes brought about by the Bill, South Africa's fiscal terms<sup>1</sup>, how the fiscal terms are impacted by the Bill and current activity in South Africa's upstream<sup>2</sup> oil and gas sector. The report then focuses on the most significant change made by the Bill, which is the level of State Participation.

A fit for purpose economic model was built and the resulting cash flows were used to calculate the economic indicators presented in the results. The results from the model indicate how the increase in State Participation levels affects the ranking of South Africa's fiscal terms and the profitability of hypothetical investment opportunities.

When ranked on fiscal terms, the country moves from having some of the best terms in Africa without the new Bill, to a position where the fiscal terms can be described as average or even onerous, depending on the interpretation of the State Participation clause. Accordingly, the result of the hypothetical investment opportunity has very positive economic indicators without the changes from the new Bill. If the most optimistic interpretation of the State Participation clause is modelled, the opportunity is less attractive but still viable and if the most pessimistic interpretation is modelled, the opportunity wouldn't warrant investment.

Even though South Africa has limited reserves, significant exploration activity is taking place under the existing legal and fiscal framework. If the Bill is implemented in its current format, it is likely that the country will see a significant decline in investment in the upstream oil and gas industry. Attracting new investment by international oil & gas companies in an environment governed by the terms of the proposed Bill will be challenging.

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<sup>1</sup> A set of laws, regulations and agreements which governs how the financial benefits of upstream oil and gas projects will be divided between the Contractor, Government, National Oil Company and BEE Partner.

<sup>2</sup> The oil and gas industry is divided into three major sectors: upstream, midstream and downstream. The upstream sector includes exploration and production (extracting oil and gas from the reserve). Midstream activities include the processing, storing, transporting and marketing of oil and gas. The downstream sector includes refining and distributing the by-products down to the retail level.

## DECLARATION

I, Maryke Louise Ellis, declare that this thesis and the work presented in it are my own. It is submitted in partial fulfilment of the requirements of the degree of Masters in Commerce, Financial and Risk Management at the University of Cape Town.

Where I have consulted the published work of others, this is always clearly attributed and where I have quoted from the work of others, the source is always given.

Signed: 

Signed by candidate
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Date: .....8 May 2015.....

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## LIST OF ABBREVIATIONS

b/d	: barrels per day
Bcf/d	: Billion cubic feet per day
BEE	: Black Economic Empowerment
boe	: Barrels of oil equivalent
capex	: Capital expenditure
DMR	: Department of Mineral Resources
E&P	: Exploration and production
EBIT	: Earnings before deduction of interest and taxes
EMV	: Expected monetary value
FPSO	: Floating production storage and offloading unit
HDSAs	: Historically disadvantaged South Africans
IRR	: Internal rate of return
Mcf	: Thousand cubic feet
MCFS	: Minimum commercial field size
MM	: Million
mmbbl	: Million barrels
mmscf/d	: Million standard cubic feet per day
MW	: Megawatt
NPV	: Net present value
opex	: Operating expenditure
P/I	: Profit to Investment ratio
PASA	: Petroleum Agency South Africa
Pg	: Probability of geological success
Tcf	: Trillion cubic feet
TCP	: Technical cooperation permit



## 1. INTRODUCTION

The Department of Mineral Resources first published the Mineral and Petroleum Resources Development Draft Amendment Bill on 27 December 2012. The Bill makes numerous amendments to the Mineral and Petroleum Resources Development Act 2002. A central focus of this report is the changes to State Participation and the impact this is likely to have on investment in the oil and gas industry.

The Bill is still in the final stages and has been referred back to the National Assembly by President Jacob Zuma for review.

The Bill has far-reaching consequences for the upstream petroleum industry in South Africa.

The upstream petroleum industry is made up of Exploration and Production firms. Due to there being only a few oil or gas discoveries in South Africa, exploration is considered to be a high risk venture with low prospects of finding commercial quantities of oil or gas. Lenient and stable fiscal terms are therefore required to attract major investment.

Upstream petroleum is an industry with long-term horizons and companies have to think decades ahead when making investment decisions. Companies prefer stable fiscal systems while onerous and unpredictable regulatory change will negatively impact investment. Consequently, investors must take reasonable steps to reduce the risk to their operations by managing their exposure to commercial and regulatory risks. Over the past few years South Africa's lenient and stable fiscal system has contributed to the influx of oil companies such as Shell, ExxonMobil, Total, Cairn India, Silver Wave Energy and Anadarko.

International oil companies are able to allocate capital investment to the most attractive exploration opportunities that they have identified regardless of geography. Countries and regions that are attempting to attract investment to exploration opportunities are therefore competing globally with other opportunities for capital investment.

The new reality of lower oil prices, which may be sustainable to a degree in the longer term, is likely to reduce investment in the industry as a whole, making it even more important to maintain a competitive position in South Africa in order to attract investment.

The new Bill, if implemented, could damage the view that South Africa provides a stable operating ground. There are many substantive amendments in the Bill which are highly likely to discourage

further investment in South Africa's oil and gas industry. That capital will simply be allocated elsewhere by the international oil and gas companies. On the other hand, the Government, National Oil Company<sup>3</sup> and BEE Partners should also receive a fair and appropriate share of revenue from the oil and gas industry. The question is whether the new Bill would be likely to distribute profits fairly and whether the increased benefit to the National Oil Company and BEE Partners will deter investment by destroying South Africa's competitive global position.

## 1.1 Research Objectives

There have been a number of criticisms of the new Bill and in line with the significant impact that the bill may have on the financial feasibility and risk of exploration and upstream activities in South Africa, this study will:

- summarise the key legislative changes brought about by the Mineral and Petroleum Resources Development Amendment Bill,
- provide an overview of the South African fiscal terms that apply to the oil and gas sector,
- provide an analysis of how the fiscal terms will change if the Bill is approved,
- present a background to the activity in South Africa's upstream oil and gas sector

The major research objectives are to:

- build a customised economic model that encapsulates the South African fiscal terms and the potential changes to State Participation. The model will be used to evaluate hypothetical oil and gas development scenarios. The resulting cash flows will be used to:
  - analyse and quantify how the change in the State Participation clause will affect South Africa's fiscal ranking against other African countries
  - analyse and quantify how the change in the State Participation clause will affect the economic worth / profitability of individual investment opportunities (using a hypothetical oil and gas development scenario) and hence, the attractiveness of investment opportunities in South Africa's upstream oil and gas sector

The results will give an indication of whether some of the critique of the new Bill is justified. It will indicate whether South Africa's current fiscal terms result in the Government, National Oil Company

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<sup>3</sup> A National Oil Company is an oil company that is fully or in the majority owned by the national Government. The National Oil Company in South Africa is Petroleum Agency SA (Petro SA).

and BEE Partners getting a fair share of the profits and what the split will be like if the Bill is implemented. It will also provide a basis for reviewing the State Participation clause and to demonstrate its potential impact on future investment in South Africa's upstream oil and gas industry.

The remainder of the thesis is set out as follows:

Chapter 2 contains a literature review and analysis of the legislative framework. In chapter 3, the methodology of the study is analysed. Chapter 4 contains the results of the fiscal comparison and the economic analysis of hypothetical developments and chapter 5 concludes the research and the findings of the thesis.

## **2. LITERATURE REVIEW AND ANALYSIS OF THE LEGISLATIVE FRAMEWORK**

The Mineral and Petroleum Resources Development Amendment Bill has received a lot of attention in the press therefore some of the material in the literature review has been taken from news and business articles that provide updates on the progress of the Bill and the general sentiment of industry players and experts on the impact the new Bill could have on the industry. Other literature includes South African laws, regulations and proposed legislation that are pertinent to the upstream oil and gas industry. Another important source of information comes from industry specific resources like IHS Energy Information, Software & Solutions, and Wood Mackenzie Upstream Oil and Gas. The remainder of the material comes from books on decision analysis for petroleum exploration, journals and peer reviewed publications.

Firstly, this chapter analyses the current legal framework and the approval channels the Bill has passed through and still needs to pass through before it becomes law. The key changes brought about from the Mineral and Petroleum Resources Development Amendment Bill are reviewed and potential problems with the changes are noted.

Secondly, South Africa's fiscal terms are reviewed. The fiscal terms are later used as assumptions in the building of a cash flow model to evaluate the impact of the State Participation changes proposed by the Bill.

Thirdly, this chapter looks at how two prominent oil and gas producers, UK and Libya, changed their fiscal terms and the impact it had on investment in their respective oil gas industries. The lessons that can be learnt by South Africa are also discussed.

Fourthly, the activity in the South African upstream oil and gas sector is investigated to determine what oil and gas reserves the country has, the composition of the industry players and what activity is currently taking place.

Lastly, this chapter analyses the valuation of opportunities in the upstream oil and gas sector and what makes them unique. We also determine how different countries' fiscal regimes and geographical locations affect profitability and list what the characteristics are for a good measure of profitability.

## 2.1 Legal framework and key changes

The South African upstream petroleum industry is primarily directed by the following laws, regulations and contracts:

- 2002 Mineral and Petroleum Resources Development Act No. 28. The law, as currently amended by the Minerals and Energy Laws Amendment Act No. 49 of 2008, governs petroleum exploration and production activities in general
- the 2004 Mineral and Petroleum Resources Development Regulations
- the 2008 Mineral and Petroleum Resources Royalty Act No. 28 (as amended by Act No.17 of 2009)
- 2008 Mineral and Petroleum Resources Royalty (Administration) Act no. 29
- 1962 Income tax Act No. 58 (Schedule 10). Schedule 10 was added to the 1962 Act by the 2006 Revenue Laws Amendment Act and is specific to oil and gas activities
- 2007 Model Contract. Petroleum rights are issued under royalty/tax arrangements

The Mineral and Petroleum Resources Development Amendment Bill is moving through the approval process and likely to be added to the above list in the near future.

The Department of Mineral Resources first published the Mineral and Petroleum Resources Development Draft Amendment Bill on 27 December 2012, and afforded interested and affected parties only 30 days to comment. Little changes were subsequently made and many damaging provisions have been retained.

The bill makes numerous amendments to the Mineral and Petroleum Resources Development Act 2002, which was previously amended by the Mineral and Petroleum Resources Development Act 2008.

On 12 March 2014, the Mineral and Petroleum Resources Development Amendment Bill was passed by the South Africa National Assembly and on 27 March 2014 it was passed by the National Council of Provinces. The bill does not become law until it is signed by the President and published in the Gazette.

On 20 January 2015, President Jacob Zuma referred the Bill back to the National Assembly, stating that “it did not pass constitutional muster”.

The key changes and the analysis of the likely impact thereof, as they relate to the South African upstream petroleum industry are as follows:

- **Free carried interest**

Section 86A(2) of the Bill grants the State (National Oil Company) an automatic right to acquire a 20 percent free carried interest in all new exploration and production rights (including production rights derived from existing exploration rights). The definition of “free carried interest” isn’t clearly defined. This is a gap in the current version of the Bill. It could mean anything from an exploration phase carry (contractor pays National Oil Company’s share of exploration costs) to a complete carry (contractor pays all National Oil Company’s costs) of all project expenditures. These two assumptions represent end members in a continuum of possibilities and are reflected in the results section where the impact of the National Oil Company participation is quantified. It is normal industry practice to clearly define which phases of the project the National Oil Company is carried for and whether they are required to repay any of the costs. The carry phase, repayment requirements (if any) and the source of repayment varies from country to country and no general rule exists that can be applied to this section of the new Bill.

The Bill also provides that the State, upon acquiring the free carried interest, shall enter into a joint operating agreement with the right holder and may appoint two representatives to the joint project committee of the exploration or production operation to represent the interests of the State.

The clause further states that the State is also "entitled to a further participation interest at an agreed price; or [in the form of] production sharing agreements". This clause has the effect of granting the state an unlimited participation interest in the right/s.

It is not clear what "an agreed price" means or how a deadlock would be broken where the State is "entitled" to an interest, but cannot agree with the exploration company in question on a price for that interest.

- **Strategic minerals**

The provisions relating to strategic minerals now also relate to "petroleum and petroleum products". This means that petroleum and petroleum products may be declared "strategic minerals". Under Section 49 of the Mineral and Petroleum Resources Development Bill, the Minister may prohibit or restrict the granting of exploration and production rights for strategic minerals at any time.

- **Application of the Amendment of the Broad-Based Socio-Economic Empowerment Charter for the South African Mining and Minerals Industry (Mining Charter) to the upstream petroleum industry**

The Bill grants the Minister discretion to require that an applicant for an exploration or production right comply with the historically disadvantaged South Africans (HDSAs) ownership requirements of the Mining Charter. Transformation in the up- and downstream petroleum industry is currently governed by the Charter for the South African Petroleum and Liquid Fuels Industry on Empowering HDSAs in the Petroleum and Liquid Fuels Industry (Liquid Fuels Charter). If the Minister of Mineral Resources exercises her discretion to apply the Mining Charter to a particular application for a new exploration or production right, the participating interest of HDSAs will increase from 9 per cent (which in practice became 10%) to 26 per cent for all new offshore exploration or production rights. The impact of the increase in BEE equity is also included in the analysis under the results section.

- **Processing of petroleum exploration and production applications by regional managers**

The Bill disbands the Agency for Promotion of Petroleum Exploration and Exploitation SOC Limited (more commonly referred to as the Petroleum Agency South Africa (PASA)), the regulator of the upstream oil and gas industry. The Bill requires that the Minister designate the Department of Mineral Resources' (DMR) regional managers to perform functions currently performed by PASA (Webber Wentzel, 2014).

PASA has specialised oil and gas industry experience, while the DMR have been responsible for handling mining applications and have little or no expertise in the upstream petroleum industry. Consequently, it is expected that the processing of applications is likely to be significantly delayed.

The disbandment of PASA would substantially impair communication between international oil companies and the DMR and present international oil companies with an additional barrier to entry that would negatively affect South Africa's global competitiveness.

- **Creation of a subsidiary by a listed company**

In terms of the Bill, a listed company, holding an oil and gas right or an interest therein, or that holds an interest in a company that holds an oil and gas right or an interest therein, may not separate from any interest in the company without the prior written consent of the Minister. In practice the international norm is for listed companies to hold local oil and gas assets through local subsidiaries. South Africa is currently no exception - most listed companies hold their South African oil and gas assets through a subsidiary. This amendment will place undue trading restrictions on listed companies (Oberholzer, 2013).

## **2.2 South African Fiscal Terms**

Any decision to invest in exploration is a complex undertaking. It is based on companies' perceptions of risk and prospectivity and the commercial reward expected from a discovery. One of the primary determinants of value is the fiscal regime under which the oil or gas would be developed and produced. These vary widely between different countries, but in principle are expected to be more or less generous to the investor depending on the scale and quality of the host nation's oil and gas resources and the inherent technical and commercial risk (Quin et al, 2010).

Countries which offer terms which are perceived by the industry to be 'in balance' with their respective oil and gas prospectivity, are likely to attract relatively high levels of industry investment and activity. Conversely, there is likely to be a low level of exploration activity where investors have judged that the terms offer them little chance of delivering value consistent with their shareholders' expectations (Quin et al, 2010).

Oil companies have obligations to seek the greatest return for their shareholders. At the same time, national governments, as the owners of the reserves, have irrefutable rights to a share of the revenue on behalf of the citizens of the country.

Almost inevitably, the two parties will have different views of what constitutes a 'fair' share of revenues, with governments espousing their ownership rights to secure the lion's share. Oil companies assert that they bring critical financial strength and industry expertise which maximises revenue for both parties, and this needs to be appropriately rewarded. Of course, both parties have valid arguments and, in practice, companies invest more readily in countries where they perceive good prospects for making discoveries and where the fiscal terms allow them to deliver value to their shareholders from any field development (Quin et al, 2010). In effect, investment capital will be drawn to the opportunities that have the best combination of prospectivity and potential commercial returns.



The structure of fiscal terms has a significant impact on the investor favourability of oil and gas projects. The type of fiscal terms employed from country to country can be hugely varied and can differ both in the levels and timing of the State Take.

Regressive fiscal systems aren't linked to the contractor's profitability and are usually front-end loaded. Typical elements include signature bonuses, carried State participation and royalty. The government's share of profits in a regressive system does not necessarily reflect economic outcomes but they receive more stable revenue earlier in the project.

In a progressive fiscal system, the government's proportionate share of profits increases with project returns, e.g. income tax. The most progressive mechanisms are those that are aimed at reducing a contractor's upside (e.g. windfall taxes) in periods of above average profits. They are commonly linked to commodity prices or rate of return. If excessive, these mechanisms could result in returns that are inconsistent (to low) with the level of risk inherent in the upstream oil and gas industry.

From the information contained in the legal framework, a summary of the fiscal terms applicable to South African petroleum exploration and production activities can be made. This information is later used to rank South Africa's fiscal terms and to model the cash flows of hypothetical development scenarios.

The South African upstream petroleum fiscal regime is based on a royalty/tax regime and contains the following elements (Content supplied by IHS; Copyright of IHS, 2010. All rights reserved):

- **Training, Employment and Social Obligations**

There is a precedent for training and employment in 2007 model contracts (both the 2007 exploration right agreement and the 2007 production right agreement). Section 20 requires right holders to: employ historically disadvantaged South Africans having appropriate qualifications and experience; implement a programme for the recruitment, training and employment of historically disadvantaged South Africans; and pay contributions to the Upstream Training Trust to be used by the Trust for the training, education and obtaining of practical experience for historically disadvantaged South Africans and other South Africans. The 2007 agreements specify these contributions as being R1 per hectare held onshore (subject to a minimum of R1,000) and R200,000 per degree square pro rata offshore (subject to a minimum of R50,000). Right holders are also required to give preference to equipment, machinery, materials and supplies manufactured/produced by historically disadvantaged South Africans, provided such goods are competitive in terms of cost, quantity, quality and

availability. Finally, right holders are required to contribute towards the socio-economic development of the areas in which they are operating.

- **Rental**

Rental is payable yearly. The 2004 Mineral and Petroleum Resources Development Regulations specify the following payments for onshore acreage for the initial licence:

Category	A	B
Area in hectares	0 - 1000	1001 and greater
Year	Fixed Annual (R)	Rate (R/hectare)
1	1,000.00	1.00
2	1,100.00	1.50
3	1,200.00	2.00
4	1,300.00	2.50
5	1,400.00	3.00

Table 1: Rental for onshore acreage (initial licence)

On renewal of an onshore exploration right, the following rates apply:

Category	A	B
Area in hectares	0 - 1,000	1,001 and greater
Year	Fixed Annual (R)	Rate (R/hectare)
1	2,800.00	5.00
2	2,900.00	6.00
3	3,000.00	7.00

Table 2: Rental for onshore acreage (licence renewal)

For exploration rights granted over offshore acreage, the exploration fee is R200 000 per annum per degree square (about 10 000square kilometres) pro-rated as appropriate, but subject to a minimum of R50 000. The fee is increased annually by the increase in the Consumer Price Index for metropolitan areas as published by the relevant state agency.

On renewal of an offshore exploration right the exploration fee will be, for the first renewal: R225 000 per annum; for the second renewal: R250 000 per annum; and for a third renewal: R275 000 per annum per degree square in all cases pro-rated as appropriate subject to

minimum of R56 250, R62 500 and R68 750 respectively. The fees are increased annually by the increase in the Consumer Price Index referred to above.

- **Royalty**

As per Section 3-6, Schedule 1 of the 2008 Mineral and Petroleum Resources Royalty Act No. 28 (as amended by Act No.17 of 2009), the royalty rate for refined mineral resources (which includes both oil and gas) is based on the following formula:

$$\text{Royalty rate (\%)} = 0.5\% + [\text{EBIT} / (\text{Gross Sales} \times 12.5)] \times 100$$

The royalty rate must not exceed 5%.

*EBIT = earnings before deduction of interest and taxes (but never below zero) and is calculated as follows: gross sales less operating costs, including capital depreciation/amortisation related to extraction and development of minerals as per the 1962 Income Tax Act-Schedule 10, but excluding the additional oil and gas tax deductions in Section 5.2 of Schedule 10.*

- **Income Tax**

Pursuant to Schedule 10 of the 1962 Income Tax Act, the rate of tax payable on income derived from oil and gas activities is as follows:

- where the oil and gas company is resident, the rate will not exceed 28%; and
- where the oil and gas company is not resident and carries on its trade through a branch or agency, the rate will not exceed 31%.

Schedule 10 to the 1962 Income Tax Act provides that, for the purpose of determining its taxable income for any year of assessment, an oil and gas company may deduct from its oil and gas income 100% of expenditure and losses actually incurred in that year in respect of exploration or production.

Schedule 10 to the 1962 Income Tax Act further provides that in determining its taxable income for any year of assessment an oil and gas company will be allowed to deduct from its income in that year:

- an additional 100% of all expenditure of a capital nature incurred for exploration; and
- an additional 50% of all expenditure of a capital nature incurred for production.

The effect of the provisions above is to allow Investors to expense and deduct immediately 200% of the exploration costs and 150% of the development costs. Tax losses can be carried forward to succeeding years of assessment and tax assessment is ring fenced around a company's oil and gas exploration activities in South Africa as defined in Schedule 10 of the 1962 Income Tax Act. The benefit of country wide ring fencing is realised if a company has multiple Blocks with production and taxable profits from a field within one of these Blocks. Exploration expenditures from within the company's other Blocks can be deducted from existing profit streams for tax purposes. Exploration exposure is therefore reduced if a company has existing production in South Africa as the expenditures can be written off for tax purposes and the tax benefit can be realised immediately. The ability to deduct new exploration expenditures for tax purposes is also not at risk if a company has current projects producing income. Unsuccessful exploration can therefore still be deducted even though no income results from the exploration activity.

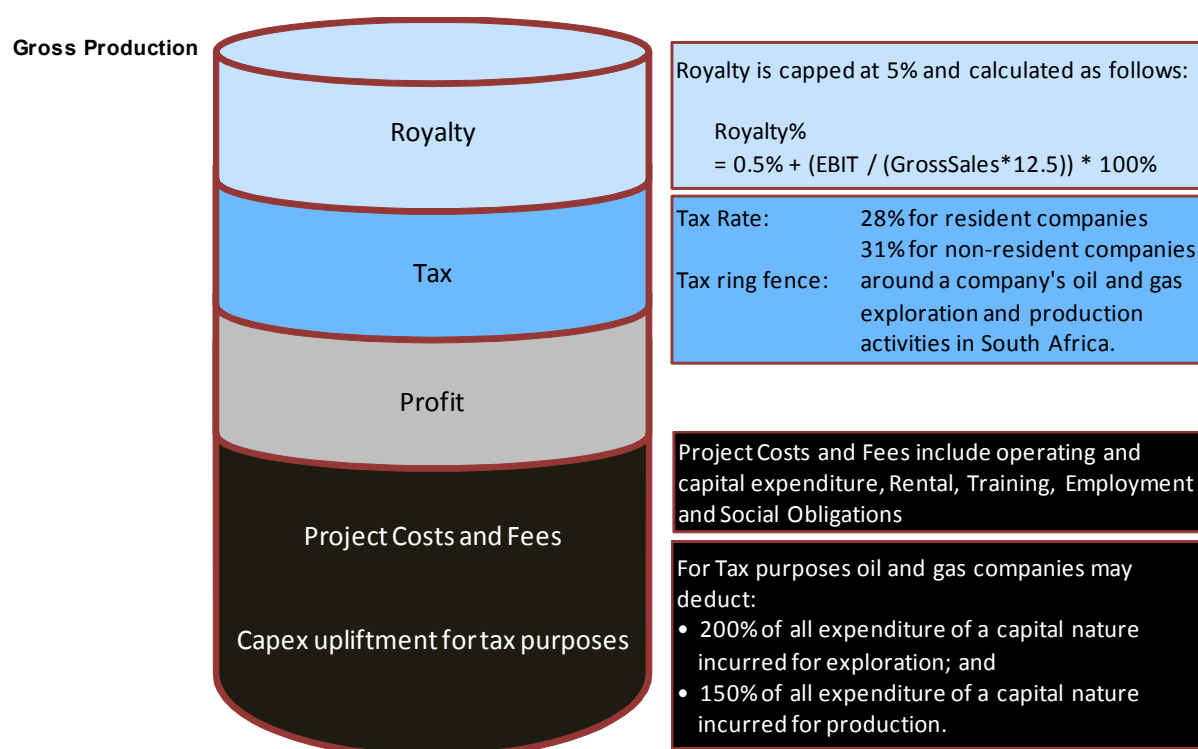
- **State Participation**

Under the terms of the model contract (2007 exploration right agreement, Section 31), the National Oil Company has the right to a minimum 10% participating interest in any production right granted over any part of the exploration area. As a member of the right holder group, the National Oil Company will pay its participating interest share of all costs and expenses related to the development plan and approved production work programmes but will not be liable for any exploration costs or expenses. As already stated, if the Mineral and Petroleum Resources Development Amendment Bill is passed, the National Oil Company would have the right to a free carried interest of 20% and would be entitled to an additional unlimited share at market related prices.

The current law dictates that in addition to the 10% participating interest allocated to the National Oil Company, a further 10% interest must be made available on commercial terms for participation by BEE companies. In terms of the Mineral and Petroleum Resources Development Amendment Bill, the stake for black economic empowerment would be raised to 26%. The reality is that "commercial terms" often means vendor financing so that the BEE

partner will effectively hold a call option. This increases the exploration exposure of the contractor, while the potential payoff will need to be shared with the BEE partner.

The figure below summarises the material components of the South African fiscal regime and was created from the preceding text:



#### State Participation

- 10% available at granting of production licence. Carried through exploration - no reimbursement.  
If the Mineral and Petroleum Resources Development Amendment Bill is passed:  
Free carried interest of 20% and an additional unlimited share at market related prices
- 10% participation on a Historically Disadvantaged Person (HDP), known as Black Economic Empowerment (BEE)  
If the Mineral and Petroleum Resources Development Amendment Bill is passed:  
26% participation on a Historically Disadvantaged Person (HDP), known as Black Economic Empowerment (BEE)

Figure 1: Key fiscal components

Figure 2 and 3 aims to depict the typical levels of State Participation across Africa and was created from raw data from industry website IHS, PEPS (Country Fiscal, Fiscal Overview, 2014). The latest available Legislation or Model Contracts were used to determine an average level of equity available to the State Participating entities in each country. Some countries have varying levels across Blocks so averages are taken. Almost half the countries have 10% or less State Participation, with over 92% having less than 30%. The three countries with 40%+ are Libya, Algeria and Angola, all of which have

vast petroleum resources and well established National Oil Companies. If the Mineral and Petroleum Resources Development Amendment Bill 2014 becomes law, South Africa, with 20% National Oil Company interest and 26% BEE interest, would fall within this 40%+ category. This would represent a markedly out-of-balance situation by African standards.

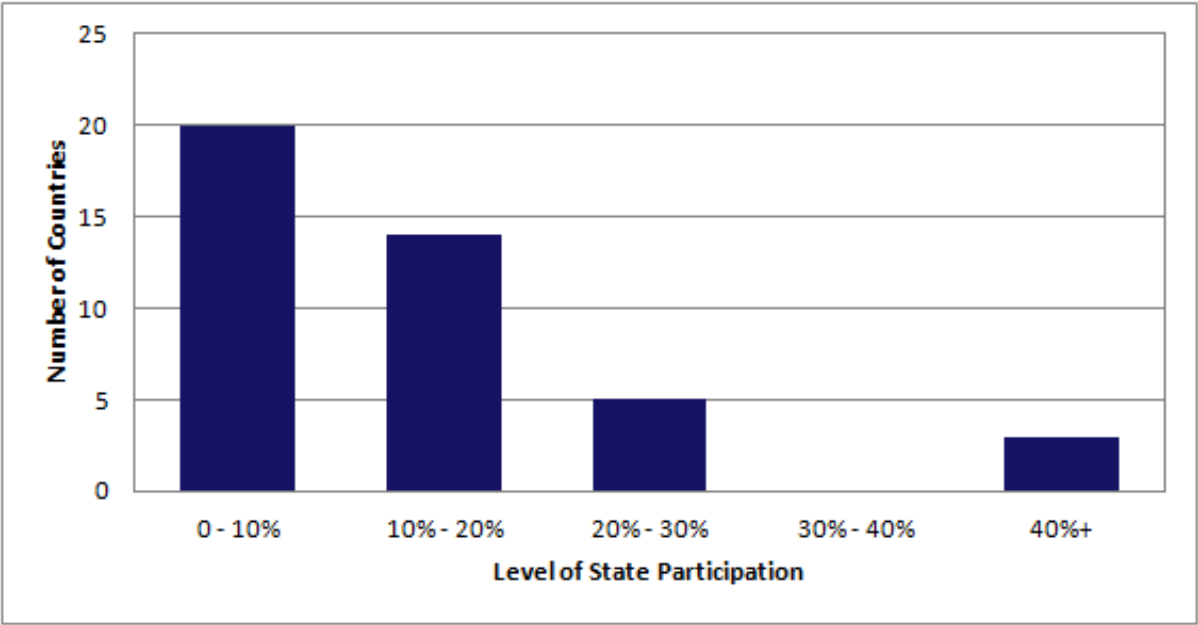


Figure 2: Grouped State Participation levels in Africa

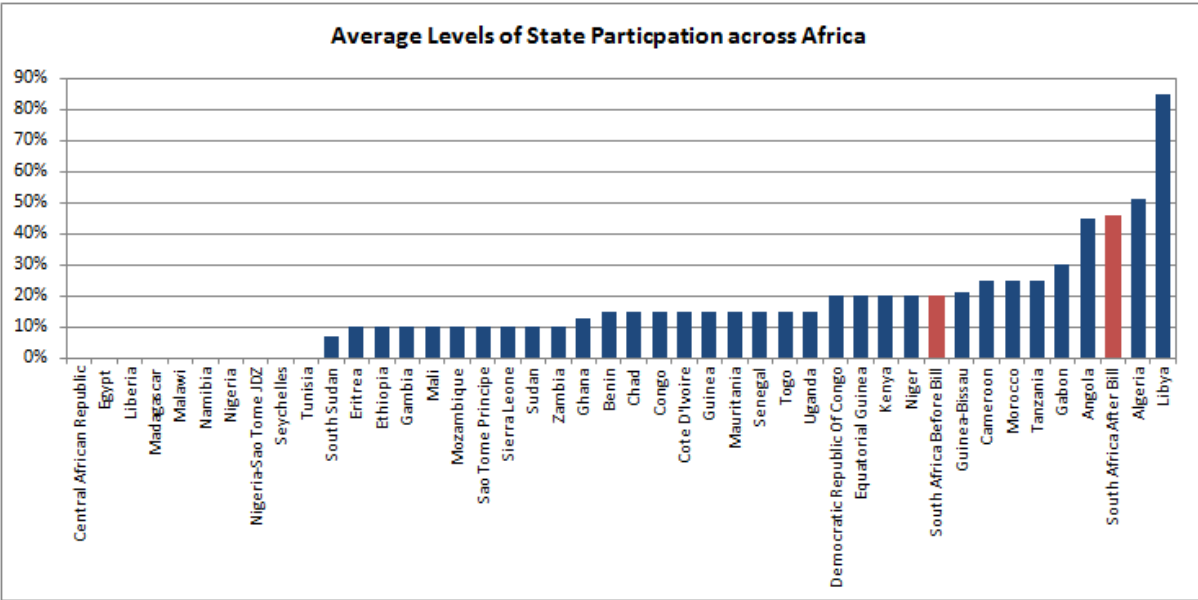


Figure 3: State Participation levels per country in Africa

## 2.3 Creating competitive fiscal terms – lessons learnt from other countries

The section that follows looks at how two prominent oil and gas producers changed their fiscal terms and the impact it had on investment in their respective oil gas industries.

### 2.3.1 Lessons learnt from the UK

Over the last 40 years, the UK has developed into one of the world's major oil and gas production countries. From an international perspective, UK is the second largest European oil and gas producer, after Norway. Worldwide, the UK is the 15<sup>th</sup> largest gas producer and 19<sup>th</sup> largest oil producer (Abdo, 2013). In the late 70s and early 80s, oil and gas resources played a significant role in the British economy (Garnaut and Clunies Ross, 1983). The main objective of this fiscal regime has been “to promote investment and production whilst striking the right balance between producers and consumers and ensuring a fair return for the UK taxpayer from national resources” (H.M Treasury, 2007).

Over the years the UK government has made numerous changes to the petroleum fiscal regime, impacting both Total State Take<sup>4</sup> and investment in the oil and gas industry.

Following the commercial discoveries of oil and gas in the UK North Sea, the tax regime tightened steadily as the UK got to grips with its newly discovered hydrocarbon riches and the implications which they might have for government revenues. Royalty was introduced, as well as a new tax on cash flow (Petroleum Revenue Tax), followed by Supplementary Petroleum Duty. The rates of the afore mentioned mechanisms were changed on numerous occasions, making the UK North Sea fiscal regime extremely complex and unstable. The instability of the petroleum regime arose from the fact that there were nine major changes over the period 1975-1982. It was so complex because of multiple applications and exemptions of taxes (Garnaut and Clunies Ross, 1983).

The Government recognised that exploration and development activities were being affected by the fiscal regime; it concluded that further development of North Sea oil was being put at risk by the high Total State Take and frequency of changes. Further, when the number of new oil and gas

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<sup>4</sup> Total State Take is the cumulative sum of all payments to the Government including royalty, bonuses, State profit oil and all taxes divided by cumulative project gross revenue minus cumulative project costs. Total State Take also includes all income derived directly from the Participating Interests of National Oil Companies and BEE partners (in the case of South Africa). The remaining portion of the divisible income is the Contractor Take.

projects being proposed by the industry started to show a significant decline, changes were made to the UK petroleum fiscal regime encouraging investments and reaping more revenues for the nation (Abdo, 2009; 2010b).

Between 1983 and 2000 the fiscal terms were relaxed, with abolishment of royalties for qualifying fields receiving development approval after 1 April 1982 (Great Britain Finance Act, 1983) and reduction of corporate tax and petroleum revenue tax rates (Abdo, 2013). The changes to the fiscal terms were intended to simplify the regime, as well as making the UK an attractive investment province for international oil and gas companies and former Prime Minister Tony Blair asserted that the UK oil industry enjoyed an “enormously favourable tax regime” (Corzine, 1998).

From 2000 onwards, the UK fiscal regime has again witnessed significant changes with the introduction of a new petroleum tax, the rate of which has subsequently been raised twice. There are a number of possible explanations for this change in taxation policy: it may be put down to the dramatic increase in oil price post 2000 (Rutledge and Wright, 2010); or it could be that the Government had realised that the type of mineral governance applied to oil and gas resources since 1983 needed to be reviewed and possibly changed, due to significant reduction in the Total State Take; or it could be a combination of the two (Abdo, 2013). Various changes were made between 2002 and 2009, mostly making the UK petroleum fiscal regime more onerous. The debate about whether the Government has de-incentivised investment in the UK oil and gas industry is evident (Muslumov, 2011 and Pfeifer et al. 2011).

The many changes in the UK petroleum fiscal regime between establishment in 1965 and 2010 and the backward and forward changes in the type of governance have deepened the instability, uncertainty and lack of clarity of the UK petroleum fiscal regime. This has negatively impacted investment in the UK oil and gas sector.

South Africa can learn from this by having a clearer and more balanced energy policy with less, or no, contradictions in its objectives and a more stable fiscal regime. Fiscal and policy instruments to maintain a suitable balance between incentivising international companies to invest in the petroleum industry, while still collecting reasonable revenues for the government, is recommended (Abdo, 2013).



### 2.3.2 Lessons learnt from Libya

Libya holds the largest amount of proved crude oil reserves in Africa, the fourth-largest amount of proved natural gas reserves on the continent, and it is an important contributor to the global supply of light, sweet (low sulfur) crude oil, which Libya mostly exports to European markets. Libya's economy is heavily dependent on hydrocarbon production. According to the International Monetary Fund, oil and natural gas accounted for nearly 98% of export revenue and over half of GDP in 2012 (IMF, 2013).

By 1969, Libya had become the world's fourth largest oil exporter, but it was receiving what were probably the lowest per-barrel revenues in the world. This opened the way to the eventual nationalisation of some foreign companies and the conclusion of participation agreements. The Government established a National Oil Company in 1970, and they were given overall control over the level of oil production in the country. In the last 30 years there have been four major fiscal regimes.

Currently they have one of the most onerous fiscal regimes in Africa. In terms of share split, contractor takes all the responsibility for exploration costs, pays for half of the development costs and only receives 10-15% of the revenue. The latest regime aims to maximise profit for the National Oil Company and disregards the economic objective of foreign oil companies. The regime can have serious effects on the field development methods and the volume of recoverable reserves. The aggressive share split is causing the contractor to refrain from investing more capital for any tertiary development strategy to raise the field recovery factor. This deficiency could be one of the most important factors behind the low recovery factor (as an average of 35%) in most Libyan oil fields in spite of the good rock and fluid characteristics. Also, some statistics show a considerable remaining volume of oil in the Libyan reservoirs (Balhasan, Towler & Miskimins, 2013).

In addition, the current fiscal regime does not take into consideration or efficiently handle the risk involved with changing oil prices. So, when the price goes down, fiscal terms are too harsh for the foreign oil companies. The onerous fiscal terms will affect the investment strategy of the most foreign oil companies and make them look for other countries in which to redirect their investments, especially in low oil price environments.

Countries like Libya with proven, prolific hydrocarbons are considerably less risky to explore than countries like South Africa with only minor proven hydrocarbons. Libya will be able to put more onerous fiscal terms in place than South Africa and still attract investment. Even so, there are still some valuable lessons from Libya that can be applied to South Africa:

- It is beneficial to have fiscal mechanisms that encourage investment to optimise the recovery factor and minimise the remaining unrecovered reserves
- Fiscal adjustments could be phased in over time, depending on the success or lack thereof in the industry
- The fiscal regime should not be so regressive that it halts investment in lower oil price environments (Balhasan, Towler & Miskimins, 2013).

## **2.4 Success in Africa and Activity in the South African Upstream Oil and Gas Sector**

### **2.4.1 Success in Africa**

While proven reserves of oil and gas in Africa today constitute just about 8% of global reserves, the continent is forecast to enjoy a high rate of growth in new discoveries. (IEA, 2014).

From 1980 to 2012, proven oil reserves increased by almost 120%, from 57 to 124 billion barrels, with at least another 100 billion barrels thought to be located off the continent's shores. Proven reserves of natural gas have increased by more than 140% during that same period, from 210 TCF in 1980 to 509 TCF in 2012 (KPMG Africa, 2013). This growth in oil and gas reserves is roughly on par with overall global growth in reserves (BP, 2013). Discoveries in sub-Saharan Africa will likely do more than merely keep pace with the rate of growth in global discoveries. The International Energy Agency (IEA, 2014) reports that almost 30% of global oil and gas discoveries made over the last five years have been in sub-Saharan Africa, reflecting growing global appetite for African resources. Recent estimates of significant recoverable oil deposits in Uganda, Ghana, Kenya and Niger, and gas in Mozambique and Tanzania, are expanding the number of countries that have the potential to become significant energy exporters (Hancock and Vivoda, 2014). As additional countries become oil and gas exporters with sizeable revenues to manage, they too must make important decisions on how to balance the interest of the state and of society with those of the international oil and gas companies, both private and state-owned, on which governments will at least initially depend for the effective exploitation of these hydrocarbons. For a region comprising some of the world's poorest countries, the potential revenues represented by these discoveries are of great significance to the producer countries themselves (Andreasson, 2015).

In 2008, oil exports contributed more than one third of total GDP in several sub-Saharan African countries, including Equatorial Guinea (88.4%), Angola (72.6%), The Republic of Congo (71%), Gabon (52%), Chad (45.1%) and Nigeria (36.9%) (African Development Bank, 2010).

Evidently, the effect of a major oil or gas discovery on a country's economy can be transformational. Attracting investment to this industry should be an important priority for governments. As mentioned in section 2.2, a country with little or no oil or gas discoveries is likely to require more favourable fiscal terms to attract investment than a country with vast, high quality oil and gas reserves.

## 2.4.2 Activity in the South African Upstream Oil and Gas Sector

South Africa's hydrocarbon reserves are not sufficient to meet the country's needs. All of South Africa's remaining liquids and gas production comes from the offshore Block 9 fields, located on the southern coast in the Outeniqua Basin. These fields are operated by PetroSA and supply the gas-to-liquids plant at Mossel Bay. With currently inadequate and declining offshore reserves, exploration is vital to increase and maintain production into and beyond the next decade. It is therefore extremely important that South Africa retains existing investors and continues to attract new investment. Table 3 contains South Africa's Reserves and Production figures (Mohammed, 2014).

Liquid Reserves (Remaining)	0.01 billion barrels (1/1/2014)
Liquid Production	3 thousand b/d (2014)
Gas Reserves (Remaining)	0.88 tcf (1/1/2014)
Gas Production	0.12 bcf/d (2014)

Table 3: South Africa's Reserves and Production

The southern Main Karoo Basin is considered to be the most prospective area for shale gas in South Africa. The volume of gas in place in the Main Karoo Basin is highly uncertain, but possible scenarios suggest that technically recoverable volumes may range from 30 Tcf to 500 Tcf. Karoo shale gas is considered to be only a prospective resource at present, and will remain undiscovered until a hydraulically fractured test well produces enough gas to be of commercial interest. The economic value of Karoo shale, in turn, will only be known once a statistically significant number of well flow rates have been measured. The long term market for gas in South Africa is likely to be strong as the country's energy needs continue to grow. However, a significant investment in infrastructure will be required before South Africa becomes a major shale gas producer (Petroleum Agency SA, 2015).

Some key companies involved in South Africa's upstream oil and gas industry are discussed below.

Petroleum Agency SA (Petro SA), the national oil company, is the most active participant in upstream activities with 14 offshore licences, of which they operate 10. They also have the option to participate through the State Participation 10% back-in right (which goes up to a 20% free carry [and beyond] if the Mineral and Petroleum Resources Development Amendment Bill becomes law) in all developments.

Black Economic Empowerment companies are encouraged to participate in the oil and gas industry. BEE companies may take a minimum of 10% (which goes up to a 26% if the Mineral and Petroleum Resources Development Amendment Bill becomes law) in licences awarded. PetroSA may take up the BEE rights in the event that no BEE company elects to participate. As yet no BEE company is actively involved in upstream projects (Mohammed, 2014).

Silver Wave Energy, a privately owned Singapore-based company, holds the biggest acreage position in South Africa. The company operates two large offshore blocks covering almost 227 000 km<sup>2</sup> and it is awaiting approval for another three blocks, which cover 120 000 km<sup>2</sup>. Silver Wave Energy is also waiting for approval for two onshore licences with a total of 10 200 km<sup>2</sup> (Mohammed, 2014).

Following its deepwater exploration success around Africa, Anadarko signed a deepwater licence for Blocks 5, 6 and 7. The company has also applied for exploration rights over Block 2C. Forest Oil and Anschutz Overseas sold their collective 76% stake in Block 2A, which holds the Ibhubesi gas and condensate discovery, to Sunbird Energy. The deal is waiting on government approval. The field contains around 60% of remaining commercial reserves in South Africa and is likely to begin producing in 2019.

The majors have recently acquired offshore acreage in South Africa. Shell was awarded the 37 300 km<sup>2</sup> Orange Basin Deepwater Block in the 2009 licensing round. Since the government lifted a ban on onshore licensing, the company is waiting for regulatory approval for an onshore exploration right licence application for shale gas. The acreage would make Shell the largest onshore licence holder with over 90 000 km<sup>2</sup>. Total was awarded a deepwater block off the southern coast and the company farmed into Block 11B/12B with CNR. ExxonMobil signed a licence for one block and agreed to jointly explore Impact Oil & Gas' three offshore areas. The agreement with Impact is subject to approval of exploration rights (Mohammed, 2014).

## 2.5 Valuation of Opportunities

The primary assets of an Exploration and Production (E&P) company are its oil and gas reserves, that is, hydrocarbons below the surface that have not yet been produced and are economically viable to extract. E&P firms are unique in that their primary asset base is depleting and therefore must be continually replaced through either drilling activities or acquisition. (Howard & Harp, 2009)

Each country is unique in terms of its expectations of exploration success, prospective field size, development costs and expectations of oil and gas prices. It will be important whether a new discovery contains heavy or light crude, is located hundreds of kilometres from a pipeline or adjacent to an export terminal (Quin et al, 2010).

Oil companies investing in South Africa expect to receive a share of revenue from any oil and gas which they take the exploration risk on and provide capital and labour to, develop and produce. The motive for being in the petroleum exploration business is to make a financial return for shareholders. The potential impact of the Mineral and Petroleum Resources Act Amendment Bill on this value will be illustrated by evaluating hypothetical developments of oil and gas fields.

Valuing upstream oil and gas interests faces particular challenges because of the high probability of failure (in the exploration phase), the extreme ranges of uncertainty in technical performance and the significant differences in other, non-technical, risks. There is less than 50% chance of encountering hydrocarbons when drilling in unproven areas and many of these discoveries will not contain commercial quantities of oil or gas (EDEN Data Search, Exploration and Production, Wells. 2015). Projects are also characterised by large capital costs and very long lead times before revenue is generated.

The skill set necessary to perform a valuation is highly specialised. Appropriate valuation techniques should be theoretically sound and must also take into account the practice in the market and explain observed behaviour. The nature of the assets make historical and current performance useful only to the extent it allows extrapolation to future performance (Moore, 2009).

There is probably no single measure of profitability that considers all of the factors or dimensions of investment projects that are pertinent to the decision maker. A company, therefore, must select a combination of profitability parameters which steer it towards its financial objectives (Newendorp, 1975).

Characteristics of a good measure of profitability (Newendorp, 1975):

- It must be suitable for comparing and ranking the profitability of investment opportunities.
- The parameter should reflect the firm's "time-value" of capital. That is, it should realistically represent the fiscal policies of the firm, including future reinvestment opportunities.
- The parameter should provide a means of telling whether profitability exceeds some minimum, such as the cost of capital and/or the firm's average earnings rate.
- It should include quantitative statements of risk (probability numbers).

The measures of profitability used to evaluate the impact of the Mineral and Petroleum Resources Development Amendment Bill are discussed under section 3.2 "Methodology of Data Analysis".

## 2.6 Summary of Literature Study

In this chapter, the key changes brought about by the Mineral and Petroleum Resources Development Amendment Bill, as they relate to the South African upstream petroleum, are discussed and potential problems with the changes are detailed. The current legal framework is used to come up with a breakdown of South Africa's current fiscal terms and how they will be affected by the new Bill. Particular focus is placed on the change in levels of State Participation and how South Africa will be markedly out-of-balance on this aspect in comparison with other countries in Africa with limited petroleum resources. South Africa's fiscal terms and the changes brought about by the Bill are used as the basis for building the economic model described in the methodology chapter and applied in the result chapter.

The section that follows analyses how two established oil and gas producers, UK and Libya, changed their fiscal terms and the impact it had on investment in their respective oil gas industries.

South Africa can learn from the UK by having a clearer and more balanced energy policy with less, or no, contradictions in its objectives and a more stable fiscal regime. The right fiscal and policy instruments to maintain a suitable balance between incentivising international companies to invest in the petroleum industry, while still collecting reasonable revenues for the government, is needed. Lessons that can be learnt from Libya are that it's beneficial to have fiscal mechanisms that encourage investment to optimise the recovery factor and minimise the remaining unrecovered reserves. Fiscal adjustments could be phased in over time, depending on the success or lack thereof in the industry and the fiscal regime should not be so regressive that it halts investment in lower oil price environments.

The next section in this chapter focuses on Africa and how the continent is forecast to enjoy a high rate of growth in new discoveries and how a growing global appetite for African resources is emerging. In South Africa the hydrocarbon reserves are not sufficient to meet the country's needs. With currently inadequate and declining reserves, exploration is vital to increase and maintain production into and beyond the next decade. It is therefore extremely important that South Africa retains existing investors and continues to attract new investment.

The last section in this chapter analyses the valuation of opportunities in the upstream oil and gas sector and what makes them unique. Exploration and production firms are unique in that their primary asset base is depleting and therefore must be continually replaced through either drilling activities or acquisition and each country is distinctive in terms of its geology, cost of development and fiscal terms. This makes the skill set necessary to perform a valuation highly specialised. A combination of profitability parameters are required to cover all the dimensions of investment projects that are pertinent to the decision maker and that steers a company towards its financial objectives. The profitability measures are expanded upon in the methodology chapter and applied in the result chapter.

### **3. METHODOLOGY**

This study reviews the changes stemming from the Mineral and Petroleum Resources Development Amendment Bill, and the results illustrate the potential changes in State Participation and the impact that these could have on the profitability of upstream oil and gas projects.

A quantitative cash flow analysis will be applied to appropriate hypothetical case studies, and a qualitative assessment of the findings of this analysis will be conducted.

This chapter includes a description of the economic model that forms the basis of the results section and a breakdown of the hypothetical development scenarios that were used as input to the economic model. This is followed by a review of the methods employed to produce the fiscal comparison data and the economic results that quantify the impact of the potential changes in State Participation. Finally, the methods used to analyse the cash flows produced by the model are described.

#### **3.1 Economic Model**

The economic model has been created to generate the free cash flow of projects on an annual basis. Cash flow analysis was selected for quantitative purposes as future cash flows is a large part of what drives a project's value and also one of the most commonly used valuation techniques (Ferris, 2013).

The economic model contains an assumptions section that includes information on the fiscal terms (royalty, tax, social contributions and State Participation assumptions) and oil and gas pricing assumptions. The inputs and modelling are in real terms with no inflationary increases. The currency of the model is in US dollars.

The State Participation assumptions are separately listed for the National Oil Company and BEE partner. The National Oil section has three different settings to capture the mechanics of this element. Firstly, the National Oil Company has 10% equity and doesn't pay for their share of exploration. Secondly, the National Oil Company has 20% equity and doesn't pay for their share of exploration. Thirdly, the National Oil Company has 20% equity and doesn't pay for any of the project costs. The BEE partner is assumed to receive vendor financing from the contractor for the exploration phase with reimbursement taking place once production begins. It is assumed that the BEE partner pays their full share of costs from the start of production onwards. There is a switch to change the percentage BEE equity between 10% and 26%.



The hypothetical development scenarios are captured as inputs and there is a separate section for the royalty, tax and State Participation calculations. The project costs and fiscal fees/payments are subtracted from the revenue on the consolidation tab to produce the free cash flow. The free cash flow provides the input to the data analysis section and various economic indicators are based on this.

## **3.2 Hypothetical Cases**

A separate oil case and a separate gas case have been evaluated to determine the impact of the changes originating from the Mineral and Petroleum Resources Act Amendment Bill on Key Economic Indicators. The parameters chosen reflect conditions in one of the country's most prospective offshore areas. The results are not intended to showcase the commerciality or feasibility of these hypothetical developments.

### **Oil Case**

A schematic of the oil case development was created for the purpose of this section and can be seen in figure 8. It is based on subsea wells producing to a FPSO (floating production storage and offloading unit). All associated gas is re-injected and there are also water injectors to maintain the pressure and recovery from the reservoir. The water depth is approximately 1450m and the total depth to the reservoir is 3330m. The mean volume for the development is 422mmbbl with capex per bbl of \$26.0/bbl and opex per bbl of \$9.1/bbl. The cost and production profiles for the oil case are illustrated in figure 6 and 7.

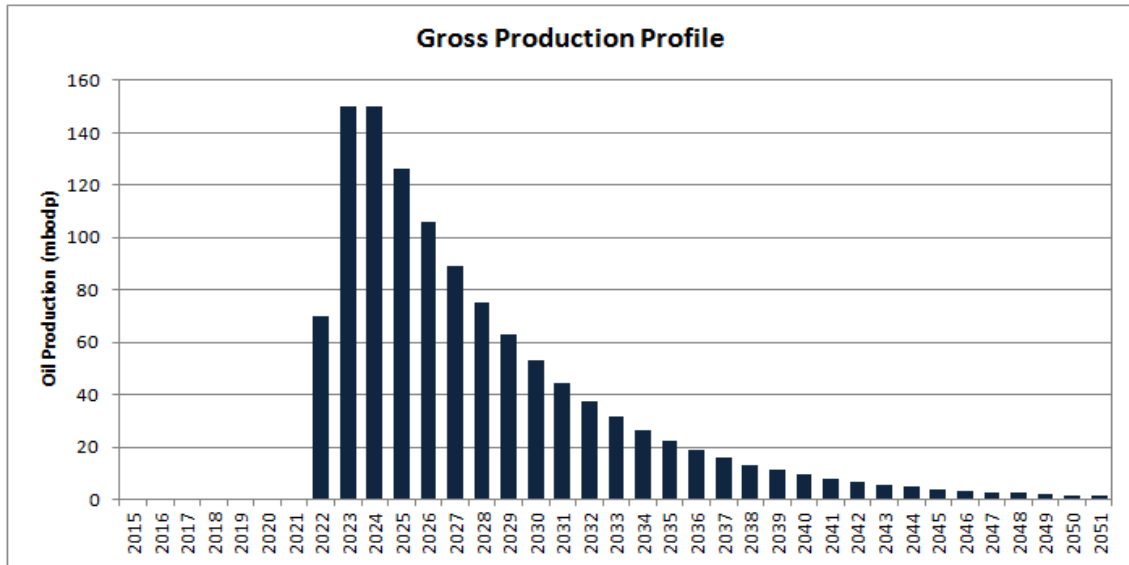


Figure 4: Gross Production Profile – Oil Case

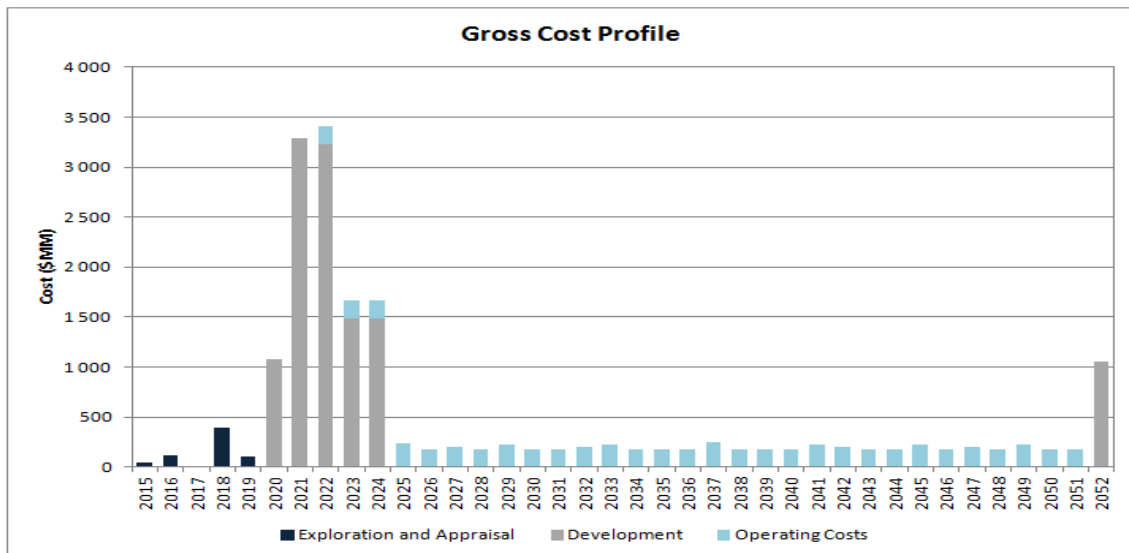


Figure 5: Gross Cost Profile – Oil Case



Figure 6: Oil Case Development Concept

### Gas Case

A schematic of the gas case development was created for the purpose of this section and can be seen in figure 11. It is based on subsea wells producing to a shallow water platform (150m water depth) located 65km from the field. The water and reservoir depth is the same as assumed for the oil case and the mean volume is 2334 BCF of gas. The development is phased with an initial development of one part of the prospect, followed by the development of the rest of prospect. Capex per boe (barrels of oil equivalent) is \$9.3/boe and the opex per boe is \$10.6/boe (gas to boe conversion of 6:1). The gas production profile has a constant plateau of 200mmscf/d to simulate the requirements of a 1600MW power station. The cost and production profiles for the gas case are illustrated in figure 9 and 10.

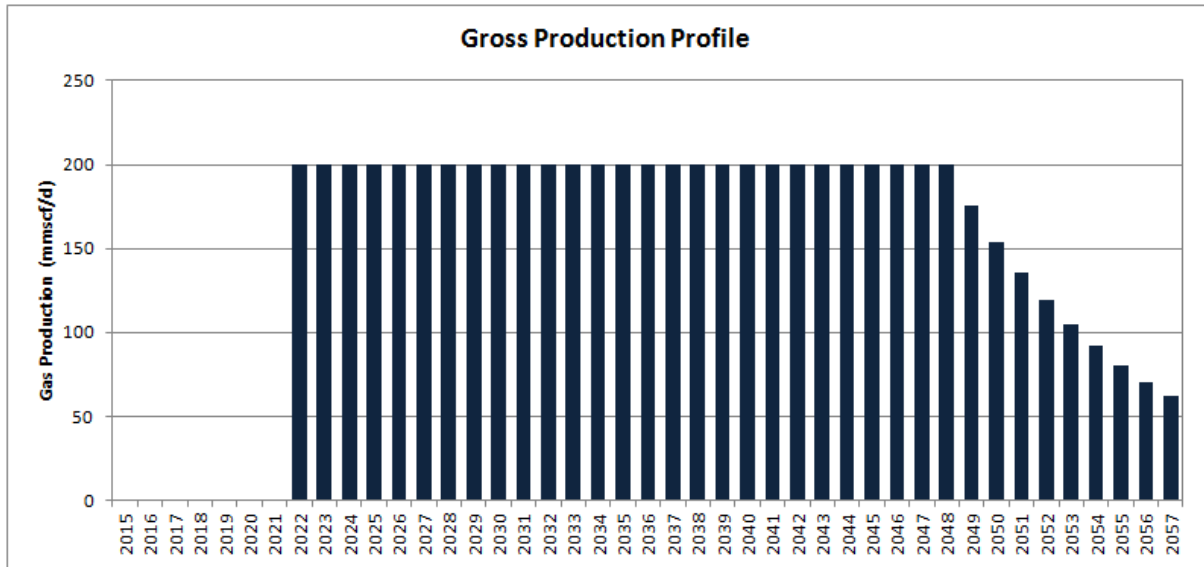


Figure 7: Gross Production Profile – Gas Case

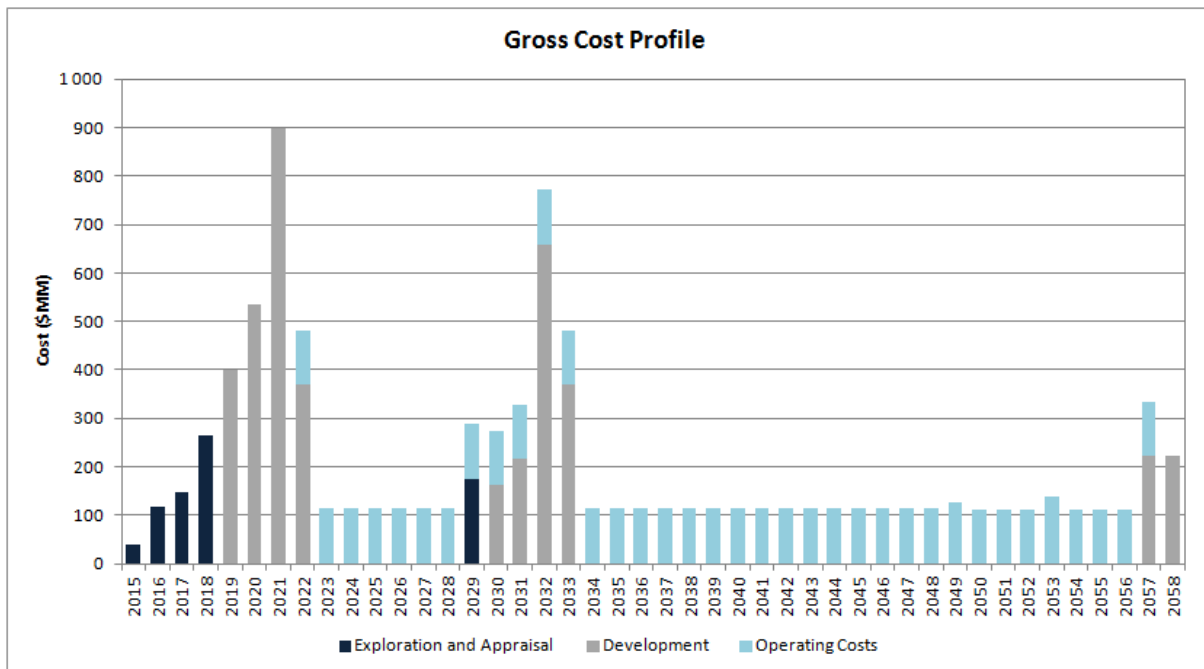


Figure 8: Gross Cost Profile – Gas Case

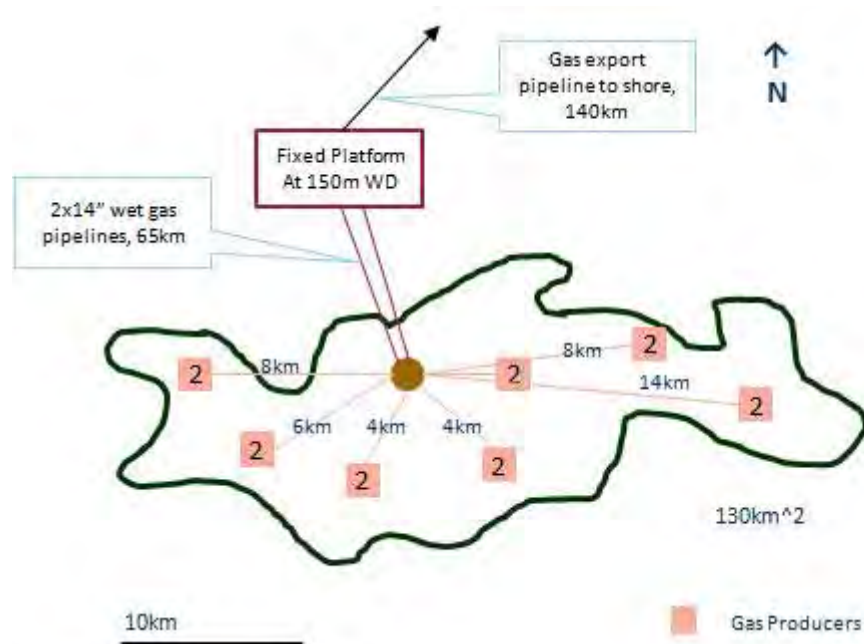


Figure 9: Gas Case Development Concept

### 3.3 Methodology of Fiscal Comparison

The fiscal comparison data originates from an industry website, IHS PEPS (Country Fiscal, Fiscal Results, 2014). The Total State Take levels for the peer group of African countries and South Africa's position without the proposed changes from the new Bill are taken from this source (see footnote 4, page 15 for definition of Total State Take).

The impact of the proposed additional State Participation is calculated in an economic model purposely built for the thesis. Numerous development scenarios were run through the model and they all resulted in similar increases in Total State Take due to the changes in the new Bill. The average percentage increase was then added to South Africa's "Before Bill" position. The "free carry" of the 20% National Oil Company Equity is modelled in two ways, one where the National Oil Company is carried for exploration (After Bill V1) and one where the National Oil Company is carried for all project costs (After Bill V2). The two methods were employed to capture different interpretations of this section of the Bill.

### 3.4 Methodology of Data Analysis

The Data Analysis section is also based on the cash flow output of the custom built economic model.

The economic model simulates the cash flow from hypothetical development cases that are appropriately costed for a deepwater development offshore South Africa. The cash flow output is used to calculate the economic indicators presented in the results. The discount rate, oil price and gas price are general assumptions and not analytically derived as the purpose of this section is to quantify the impact of the Bill and not to come up with precise evaluations for the hypothetical cases.

Firstly, the distribution of gross revenue will be illustrated, showcasing how the portion of the distributable revenue going to the contractor group is affected. The revenue is split in the portion attributable to projects costs, the portion going to the Government (including taxes, royalty and fees), the portion going to State Participation (including the National Oil Company and BEE partners) and the portion going to the Contractor Group.

This is followed by a review of annual cumulative cash flow on a time series basis. Finally we will review a select group of key economic indicators applicable to the oil industry which include:

- Net Present Value (NPV)

Discounted cash flow analysis is the most popular measure of evaluating capital projects. Approximately 90 percent of companies use a discounted cash flow model to estimate the fair value of oil and gas reserves. Discounted cash flow analysis is a method of valuing an asset using the concepts of the time value of money. All future cash flows are estimated and discounted to determine their present values – the sum of all future discounted cash flows, both incoming and outgoing, is the net present value. A single discount rate (average opportunity rate) represents the average earnings at which future revenues can be reinvested. If  $NPV=0$ , then the investment is yielding a rate of return equal to the discount rate used. If NPV is negative it means that the investment will yield a rate of return less than the discount rate. If positive, the sum represents present value cash worth in excess of making a rate of return equal to the discount rate. The discount rate used in the analysis is 10% and a midyear discounting convention is used to reflect the flow of cash that is distributed throughout the year. The 10% rate is a standard discount rate used in the oil and gas industry for real cash flows in US dollars.

- Internal Rate of Return (IRR)

The internal rate of return can be defined as the interest rate which equates the value of all cash inflows to the cash outlays when these cash flows are discounted or compounded to a common point in time. Stated differently, it is the interest rate which makes the present value of net receipts equal to the present value of the investments.

- Discounted Profit-to-Investment Ratio (P/I)

The discounted profit-to-investment ratio is obtained by dividing the NPV by the present value of the investment. This sidesteps the weakness inherent to the NPV of being independent on the absolute magnitude of the cash flows. The ratio is interpreted as the amount of discounted net profit generated in excess of the average opportunity rate per dollar invested. It is useful to select investment opportunities under the constraint of limited investment capital, when it is essential to gain the most profit per rand or dollar invested.

- Payback Period

The payback period of a capital investment project is defined as the length of time required to receive accumulated net cash flows equal to the investment. Stated differently, it is the length of time it takes to recoup the invested capital back. As such, the payback period is an approximate measure of the rate at which cash flows are generated early in the project. It tells the decision maker nothing about the rate of earnings after payback period and does not consider the total profitability of the investment opportunity.

- Minimum Commercial Field Size (MCFS)

This is the required volume to sanction a development in a given environment (e.g. water depth, geological properties, fiscal terms etc.). Put differently, the MCFS is the breakeven hydrocarbon volume for a given set of commercial assumptions. The worse the fiscal terms are, the bigger the MCFS will need to be to break even. The MCFS at the breakeven point results in an NPV of zero. Discovered field sizes smaller than the MCFS are by definition not likely to be developed / commercialised under the commercial assumptions made.

- Breakeven Price

This is the required oil price or gas price that will yield an NPV of zero. This indicates the project's sensitivity to the oil price and/or gas price and how much the price could drop before the project becomes uneconomical.

- Expected Monetary Value (EMV)

Risk is frequently the most critical factor taken into account in decisions to invest capital in exploration. EMV takes this into consideration and is a method for combining profitability estimates with quantitative estimates of risk to yield a risk-adjusted decision-making criterion. For an exploration well, you would take the algebraic sum of the expected values of each possible outcome that could occur if the decision alternative is accepted. EMV analysis strives to ensure that the potential rewards in investing in an exploration opportunity are commensurate with the risk.

An example is included below. You would therefore multiply the NPV of the mean scenario with the geological probability of finding hydrocarbons ( $P_g$ ) and add the discounted cost of failure multiplied by the probability of drilling a dry hole ( $1-P_g$ ). The cost of failure includes all the costs that would accumulate to the point of a dry exploration well (typically includes seismic and drilling costs).

$$\begin{aligned} \text{EMV} &= \text{NPV} \times P_g + \text{Discounted Cost of Failure} \times (1 - P_g) \\ \$8\text{MM} &= \$280\text{MM} \times 15\% + \quad \quad \quad -\$40\text{MM} \quad \quad \quad \times 85\% \end{aligned}$$

The decision rule for expected monetary value choices is as follows: When choosing among several mutually exclusive decision alternatives, select the alternative having the highest positive expected monetary value. On a risk-adjusted basis the rewards should always outscore the cost (Newendorp, 1975).



## 4. RESULTS

### 4.1 Fiscal Comparison

A fiscal comparison is a way to compare the fiscal terms of countries on an equal footing. The same input assumptions are used in the models for all the fiscal regimes in the comparison to generate metrics that allow us to rank the fiscal terms without the influence of varying costs, oil price, phasing or volumes. In figure 12 and 13, the development scenario is for a volume of 250mm bbl oil with figure 12 run at \$50/bbl and figure 13 run at \$100/bbl. Figure 14 is for 1.5 TCF of gas at a price of \$8/mcf. These cases are generic and purely for fiscal comparative purposes and not specific to South Africa. The results indicate which countries have the highest and lowest profit share going to the contractor group.

Although some countries have the same fiscal terms throughout all Blocks (which is most common when they fall under Royalty Tax regimes with tax and royalty rates dictated by legislation), other countries have fiscal terms that vary for each Block (mostly seen when there are Production Sharing Contracts in place, with terms that are separately negotiable in individual contracts). For the analysis in Figures 12 – 14, the most recent model contracts were used when there were varying terms in a country (Country Fiscal, 2014). The metric used for the comparison is Total State Take which in effect serves as a measure of “tax equivalence”. The level of Total State Take is an important indicator of the attractiveness of the fiscal terms.

A project with a high Total State Take will generally require large petroleum resources at a low risk level or a low cost base to make it viable as an investment opportunity. If the project is extremely robust, it can withstand more onerous fiscal terms. If it is marginal, it cannot. Everything else being equal, the higher the Total State Take, the less investment a country is going to be able to attract. In practice, certain countries have more petroleum resources that are cost effective to extract than others. In a sense, countries with proven, prolific hydrocarbons are considerably less risky to explore than countries with no or only minor proven hydrocarbons. Countries like Libya, Nigeria, Angola, Egypt, Gabon and Equatorial Guinea with existing reserves (part of the top ten list of largest oil reserves in Africa) are more likely to yield new discoveries than countries like South Africa and Namibia with only minor hydrocarbon discoveries and are therefore generally able to put more onerous fiscal terms in place and still attract investment.

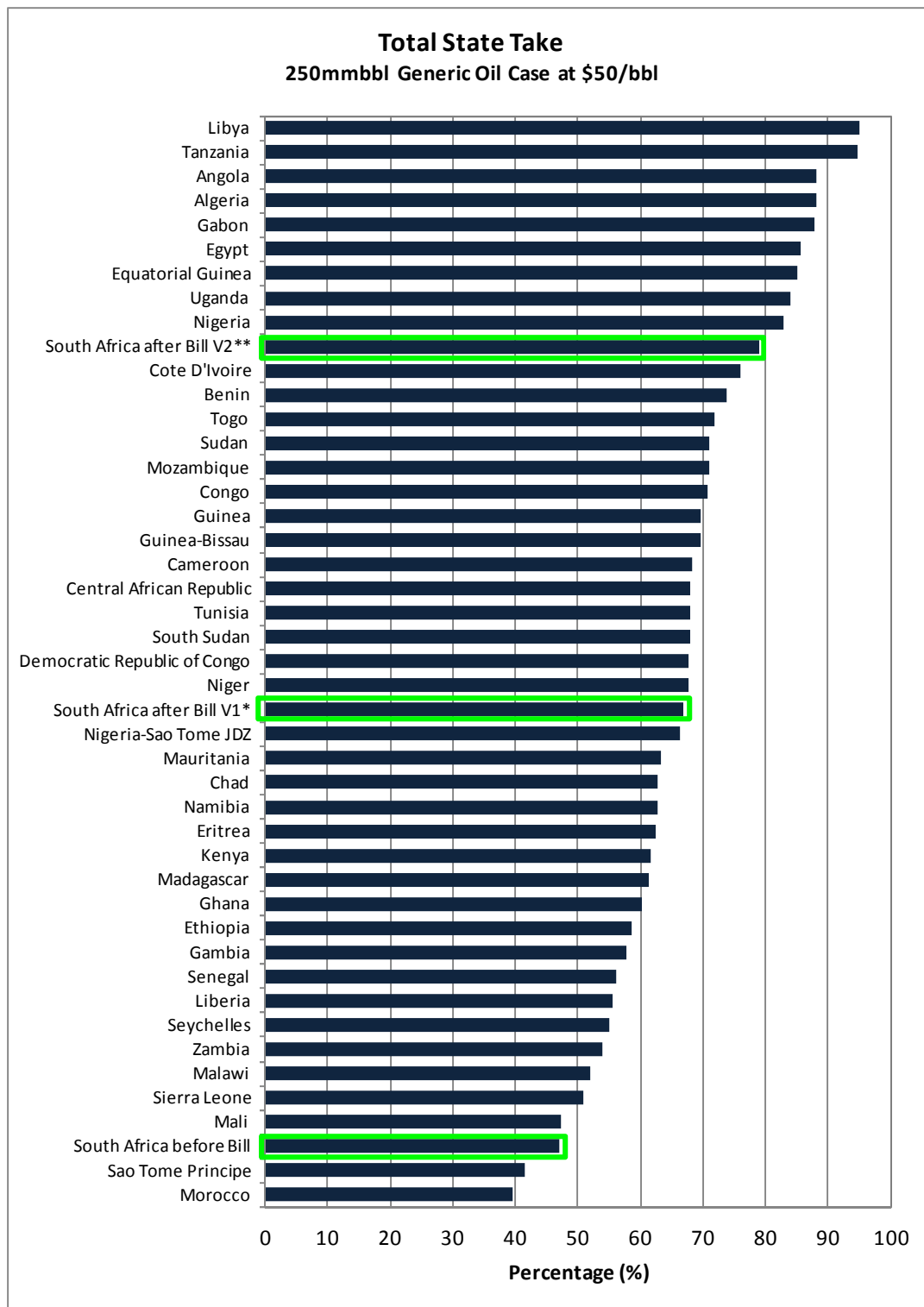


Figure 10: Total State Take – 250mmbbl Oil Case at \$50/bbl

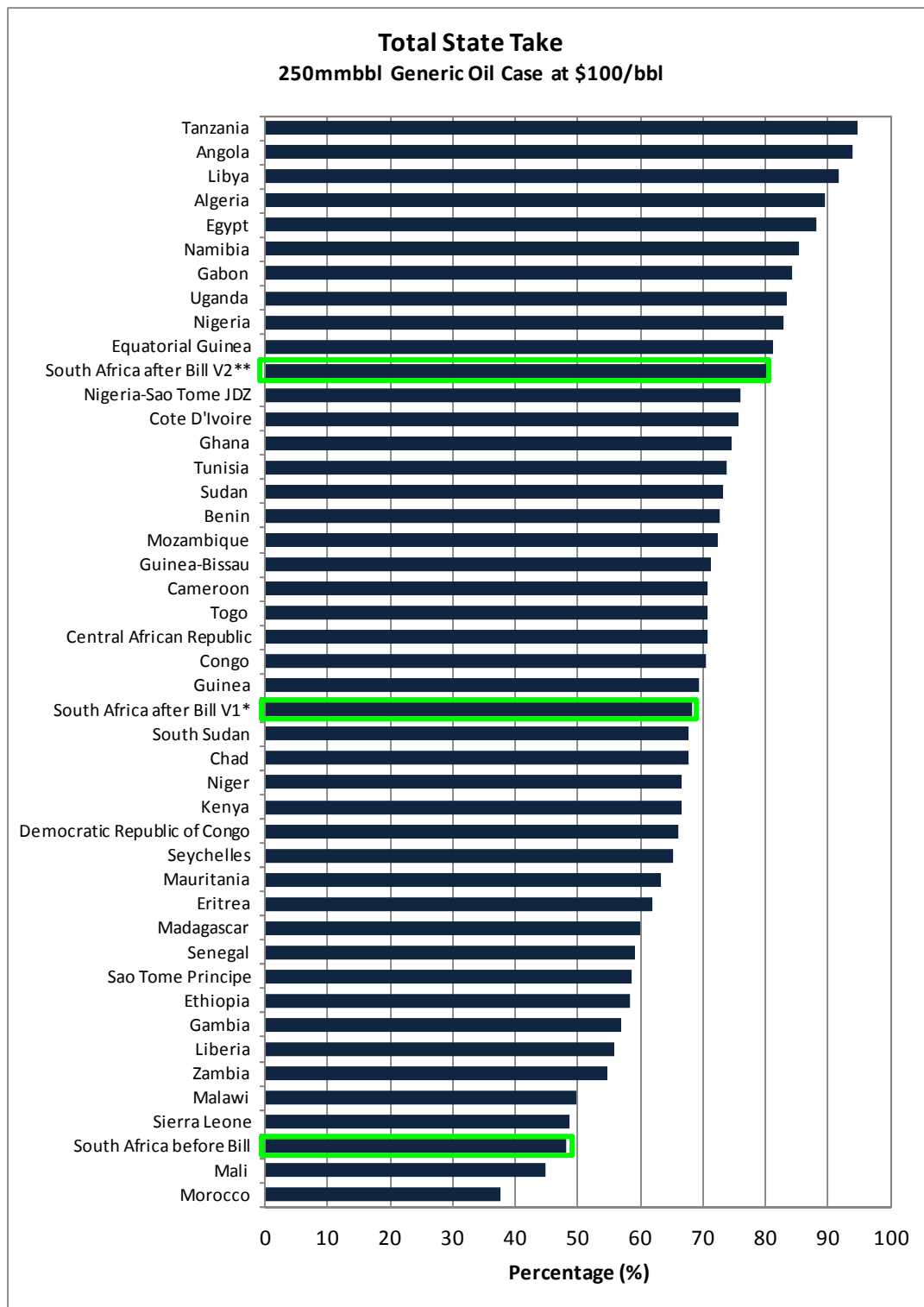


Figure 11: Total State Take – 250mmbbl Oil Case at \$100/bbl

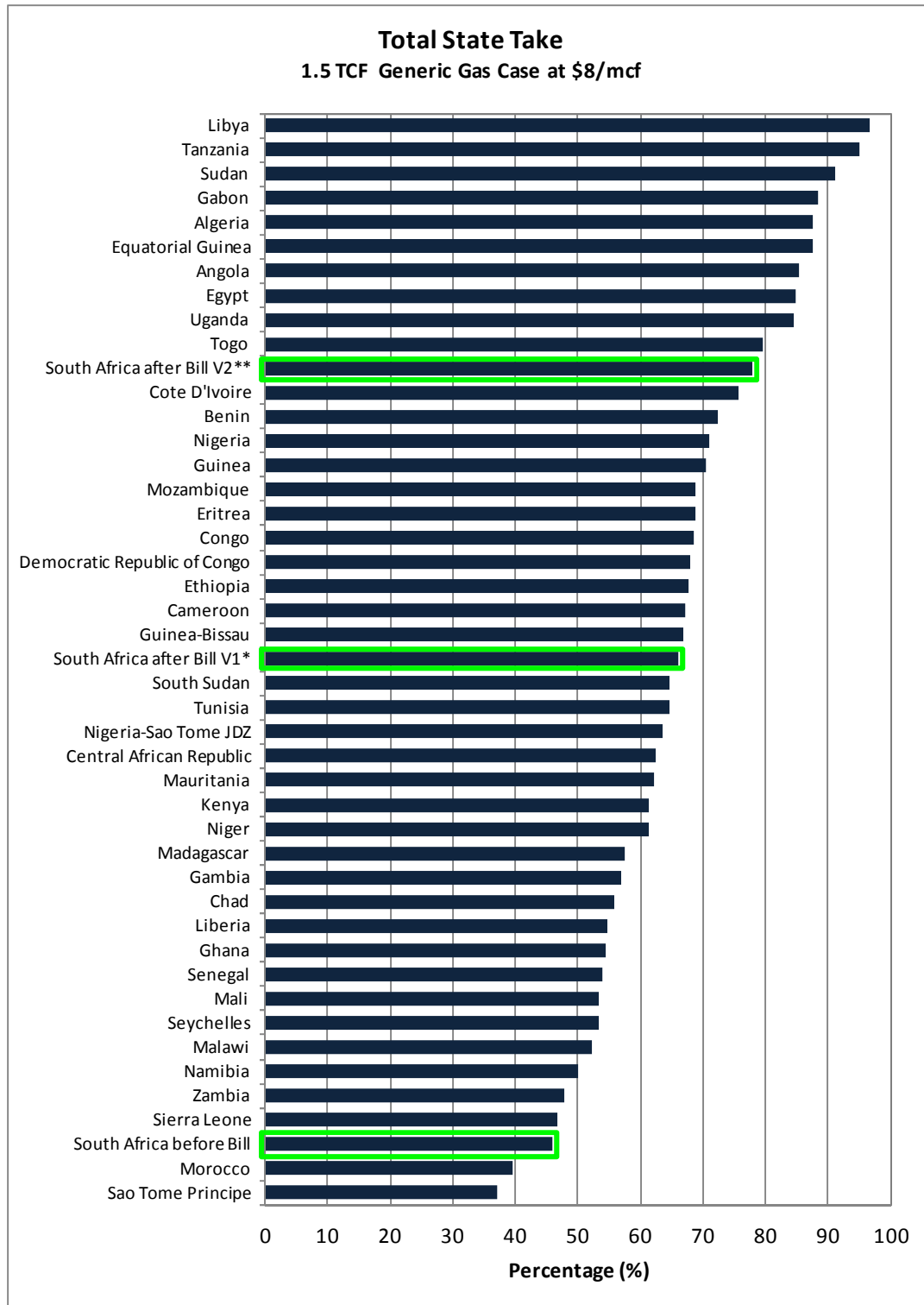


Figure 12: Total State Take – 1.5 TCF Gas Case at \$8/mcf

\* South Africa after Bill V1 - The 20% National Oil Company interest is carried for exploration only

\*\*South Africa after Bill V2 – The 20% National Oil Company interest is carried for all project costs

In both cases the BEE partner is assumed pay for all costs from the start of production. They will also reimburse the contractor for their share of past costs.

Figure 12 – 14 shows the impact of the increase in the State Participation (National Oil Company and BEE participation) element of the Mineral and Petroleum Resources Act Amendment Bill highlighted in green. In “South Africa after Bill V1” the 20% State Participation is interpreted to be carried for the Exploration phase only, while in “South Africa after Bill V2” the 20% National Oil Company interest is interpreted to be carried for all project expenses. The message from the three graphs is the same even at different oil prices and for different development concepts; the changes take South Africa from a country with an excellent fiscal system for attracting investors in “South Africa before Bill” with a Total State Take of between 40%-50% to one that’s on par with countries with vast reserves in “South Africa after Bill V2” with a Total State Take of between 70%-80%. This clearly results in inappropriately onerous fiscal terms for a country that is in dire need of new investment in hydrocarbon exploration. It is possibly worth noting that this negative fiscal effect is compounded by the uncertainty that is inherent in the proposed bill.

## **4.2 Economic Analysis**

The results of the cases described in the Data and Methodology section are in real terms and evaluated with and without the fiscal components of the Mineral and Petroleum Resources Act Amendment Bill. In this section the distribution of gross revenue is reviewed and how the contractor take and State Participation take (including National Oil Company and BEE partnership) is affected by changes in the Bill. This is followed by the review of the annual Cumulative Cash Flows before and after the Bill.

Lastly, we will review a select group of key economic indicators applicable to the oil industry, including net present value, internal rate of return, discounted profit-to-investment ratio, payback period, minimum commercial field size, breakeven prices and expected monetary value.

#### 4.2.1 Distribution of Gross Revenue

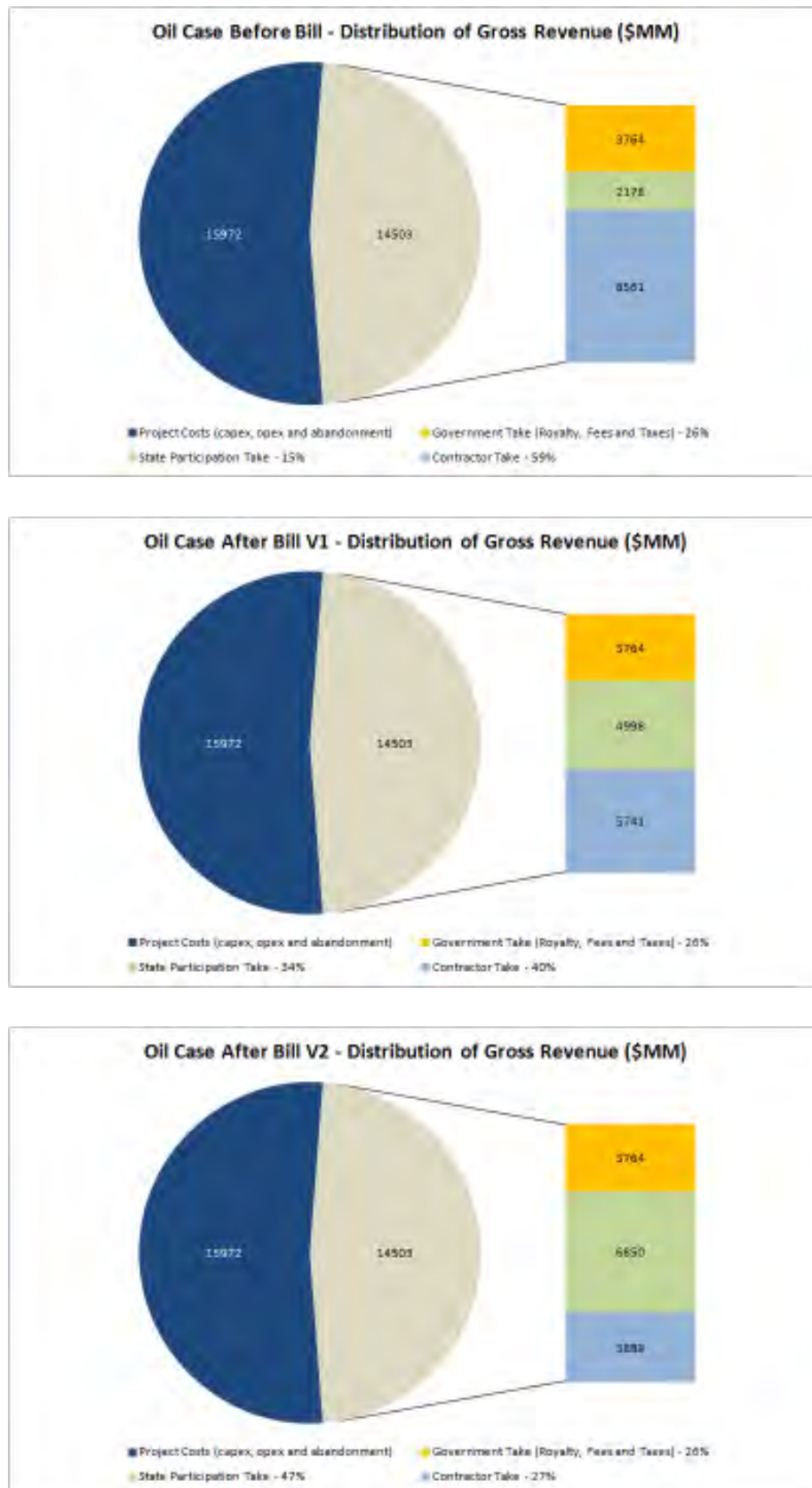


Figure 13: Distribution of Gross Revenue of the Oil Cases

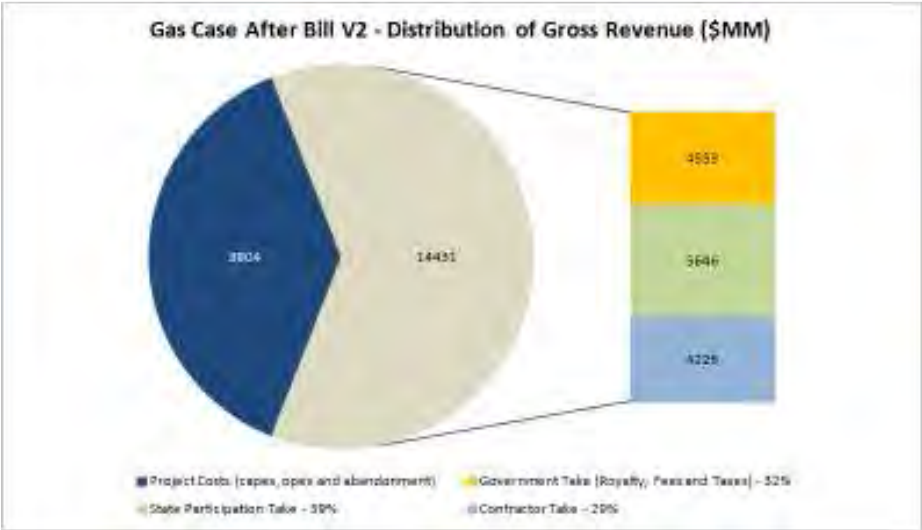
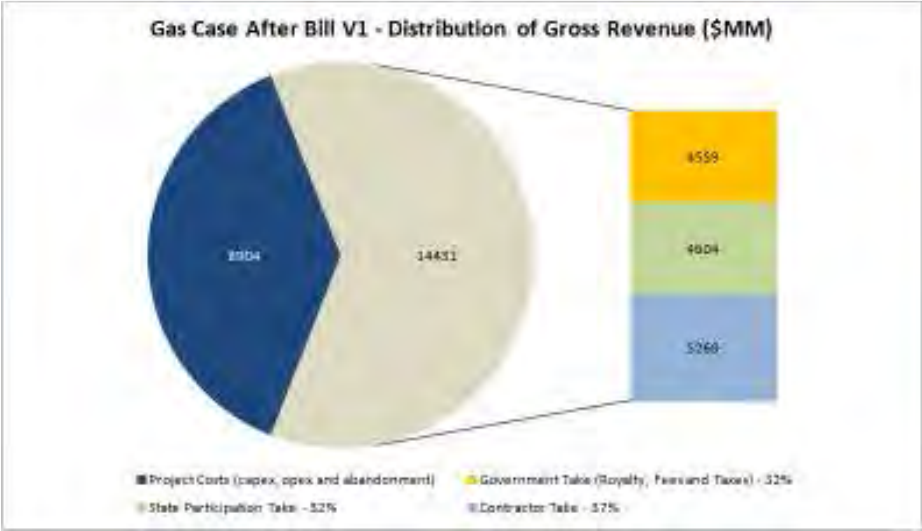
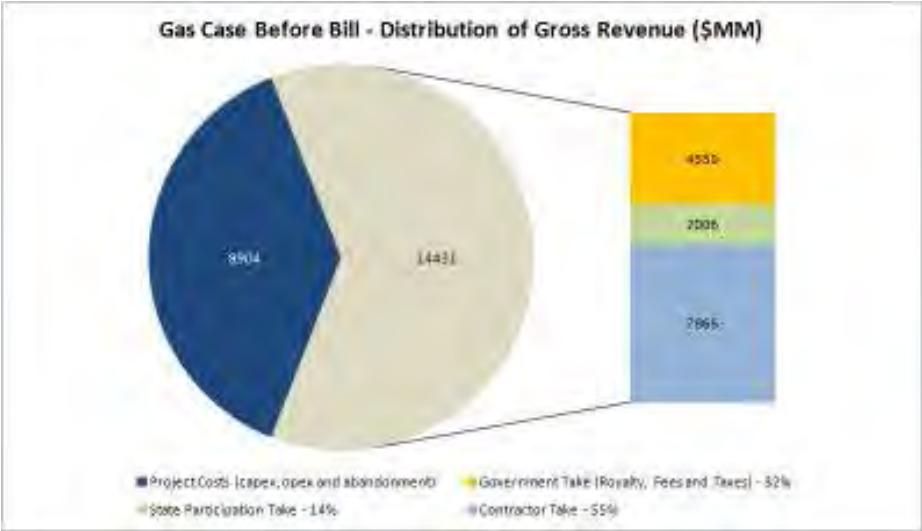


Figure 14: Distribution of Gross Revenue of the Gas Cases

The distribution of revenue for the Oil Cases is illustrated in Figure 15 and the distribution of revenue for the Gas Cases is illustrated in Figure 16, and is presented on an undiscounted basis.

Oil Cases: The government takes 26% of the distributable revenue (gross revenue less project costs) in all three scenarios. On a gross basis, the royalty, taxes and fees are the same irrespective of the equity split between the contractor and the State Participation entity (National Oil Company and BEE partner) and the carry situation. The remainder of the distributable revenue is allocated between the contractor and the National Oil Company as follows:

	State Participation Take	Contractor Take
Oil Case Before Bill	15%	59%
Oil Case After Bill V1	34%	40%
Oil Case After Bill V2	47%	27%

Table 4: Oil Case - Distributable revenue allocation

Gas Cases: The government takes 32% of the distributable revenue. The remainder of the distributable revenue is allocated between the contractor and the State Participation entity as follows:

	State Participation Take	Contractor Take
Gas Case Before Bill	14%	55%
Gas Case After Bill V1	32%	37%
Gas Case After Bill V2	39%	29%

Table 5: Gas Case - Distributable revenue allocation

The contractor moves from a position where they receive majority of the distributable revenue without the new components of the Bill, to a position where they receive less than a third of the distributable revenue. And this should be seen in the context of the contractor taking 100% of the risk for investments that generally have less a 20% chance of success (or more than an 80% chance of failure).

#### 4.2.2 Annual Cumulative Cash Flow

The annual cumulative cash flows of the contractor in figure 17 and 18 allow us to see how the three scenarios differ over time. In the exploration and appraisal phase between 2015 and 2018, the contractor pays for 100% of the costs.



	Before Bill	After Bill V1	After Bill V2
Contractor Paying Share	100%	100%	100%
National Oil Company Paying Share	0%	0%	0%
BEE Partner Paying Share	0%	0%	0%

Table 6: Exploration phase paying share

In 2019, the development phase of the field commences. Between 2019 and 2021 the three development scenarios diverge as follows:

	Before Bill	After Bill V1	After Bill V2
Contractor Paying Share	90%	80%	100%
National Oil Company Paying Share	10%	20%	0%
BEE Partner Paying Share	0%	0%	0%

Table 7: Development phase paying share

From 2022 onwards, the field is in production and it is assumed that the BEE partner repays their equity share of past costs (without interest) as well as their share of costs going forward. From 2022 onwards the three scenarios are as follows:

	Before Bill	After Bill V1	After Bill V2
Contractor Paying Share	80%	54%	74%
National Oil Company Paying Share	10%	20%	0%
BEE Partner Paying Share	10%	26%	26%
Contractor Revenue Share	80%	54%	54%
National Oil Company Revenue Share	10%	20%	20%
BEE Partner Revenue Share	10%	26%	26%

Table 8: Production phase paying and revenue share

In the three scenarios the contractor takes all the exploration risk because they pay for the exploration costs in full. This is the high risk part of the project life cycle because of the low chance of encountering hydrocarbons and the high costs of drilling a well. The possible payoff for taking this risk is substantially reduced, with only 54% of the revenue going to the contractor, if the Mineral and Petroleum Resources Act Amendment Bill is passed. The quantum of the aforementioned point is reflected in the EMV results under section 4.2.3 (7) and this is ultimately what will drive the amount of investment.

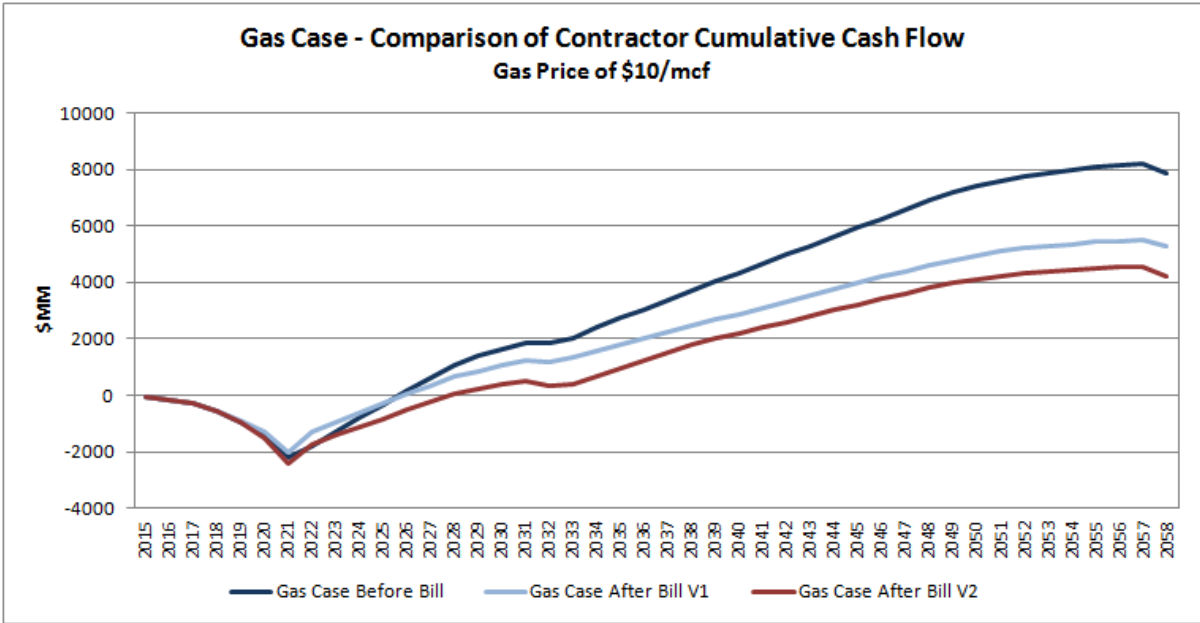


Figure 15: Oil Case - Cumulative Cash Flow

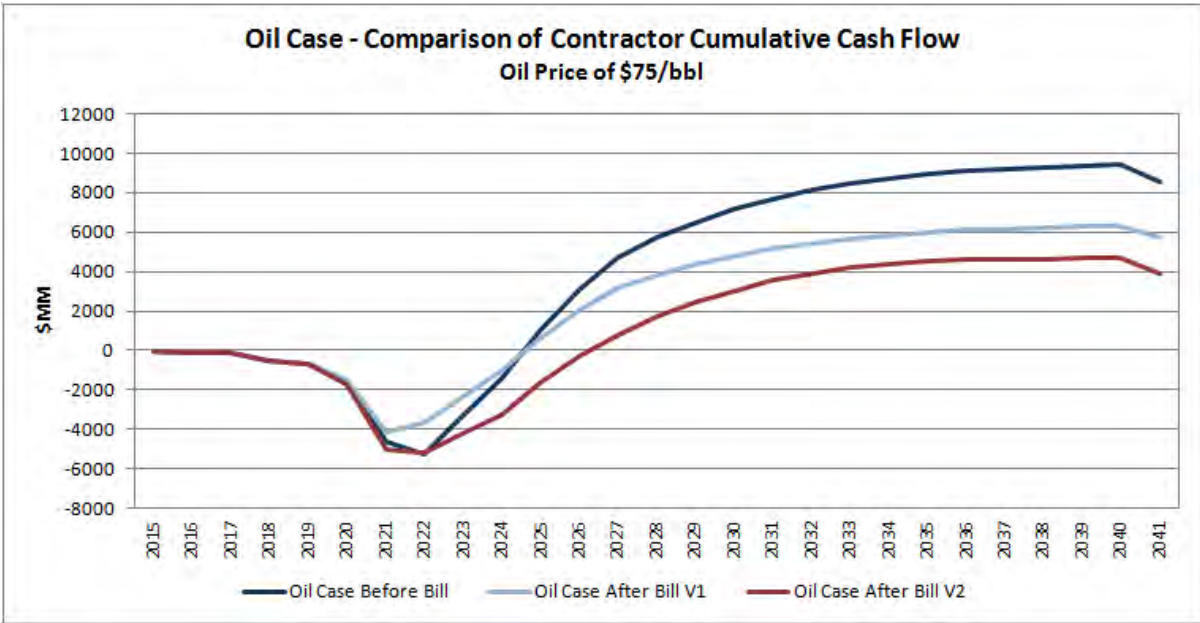


Figure 16: Gas Case - Cumulative Cash Flow

### 4.2.3 Key Economic Indicators

Companies need an objective way of measuring the economic worth / profitability of individual investment opportunities in order to have a realistic basis for choosing among them. There is probably no single measure of profitability that considers all of the factors or dimensions of investment projects that are pertinent to the decision maker, and a combination of metrics best captures the economic worth of the opportunity (Newendorp, 1975). The next section looks at these measures and how the Mineral and Petroleum Resources Act Amendment Bill affects the attractiveness of investment opportunities in the South African oil and gas sector. The first 7 metrics measure profitability without considering exploration risk and showcase the outcome assuming successful discoveries that result in the example oil and gas cases described in section 3.1. The final metric (Expected Monetary Value) combines profitability estimates with quantitative estimates of risk to yield a risk-adjusted decision criterion.

#### 1. Net Present Value (NPV)

The NPV's in figure 19 and 20 are calculated by taking the present value of cash inflows and outflows and discounting these cash flows (midyear) by 10%.

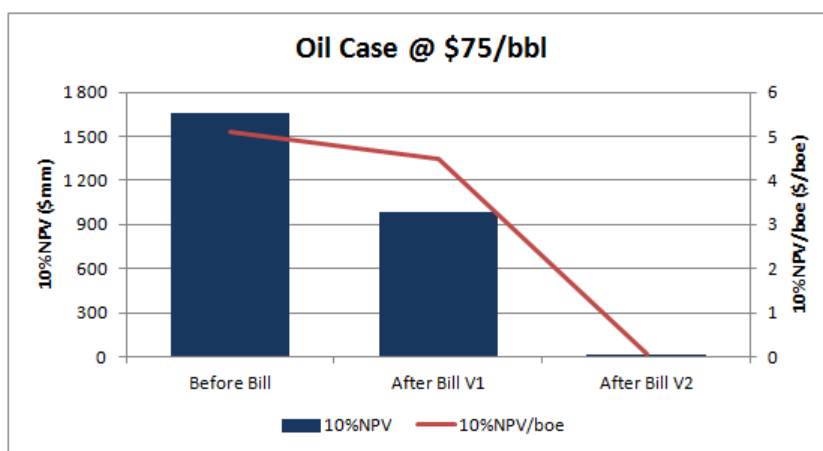


Figure 17: Oil Case - Reduction in 10%NPV and 10%NPV/boe due to changes in the Bill

In figure 19, the example oil case results in a very healthy 10%NPV of \$1655mm and a 10%NPV/boe of \$5.1/boe. The 10%NPV reduces by 41% and the 10%NPV/boe reduces by 12%, under the conditions of the Bill V1, to \$982mm and \$4.5/boe respectively. "After Bill V2" it is very close to breakeven and not an attractive result (on an unrisks basis) for a potential investor.

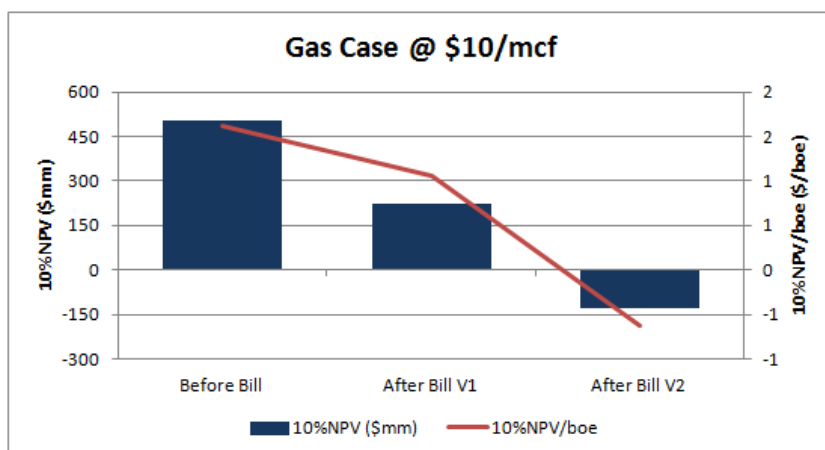


Figure 18: Gas Case - Reduction in 10%NPV and 10%NPV/boe due to changes in the Bill

In figure 20, the example gas case follows a similar trend to the oil case. The 10%NPV goes from \$503mm in the “Before Bill” case to \$224mm in the “After Bill V1” case to -\$130mm in the “After Bill V2” case. The 10%NPV/boe goes from \$1.6/boe in the “Before Bill” case to \$1.1/boe in the “After Bill V1” case to -\$0.6/boe in the “After Bill V2” case.

## 2. Internal Rate of Return (IRR)

The IRR’s in figure 21 and 22 are the discount rates required to make the cash flows of the cases equal to zero.

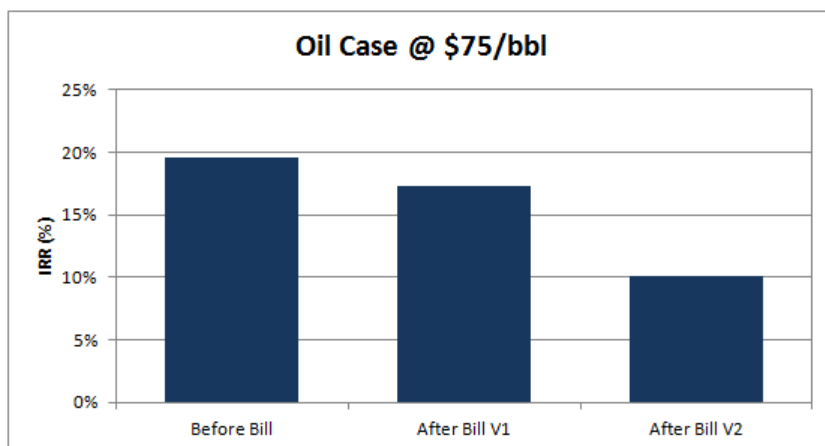


Figure 19: Oil Case - Reduction in IRR due to changes in the Bill

In figure 21 (oil case), the IRR starts at 19.5% in the “Before Bill” scenario and reduces to 17.3% in the “After Bill V1” scenario, and further reduces to a marginal IRR of 10.1% in the “After Bill V2” scenario. The IRR of the “After Bill V2” scenario would not meet the hurdle rate for most upstream oil and gas companies.

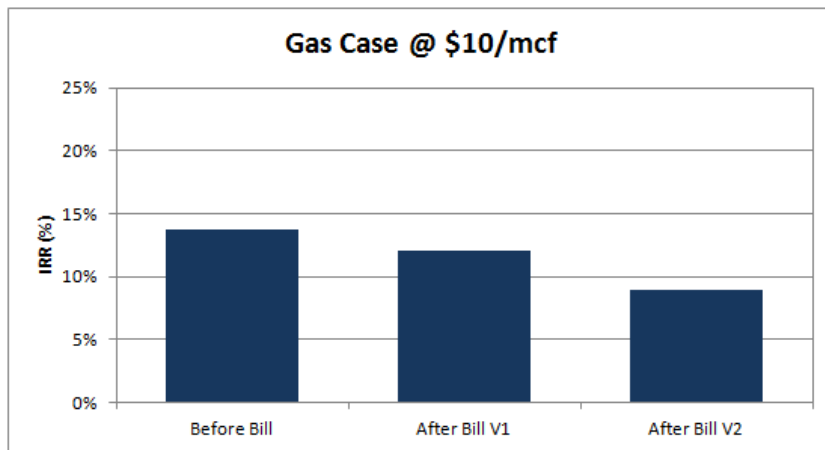


Figure 20: Gas Case - Reduction in IRR due to changes in the Bill

In figure 22 (gas case), the IRR for the “Before Bill” scenario is 13.8%. It reduces to 12.1% in the “After Bill V1” scenario and results in an IRR of 8.9% in the “After Bill V2” scenario.

### 3. Discounted Profit-to-investment ratio (P/I)

This is the NPV of the cash flows divided by the discounted investment. A 10% discount rate is used for this metric in figure 23 and 24.

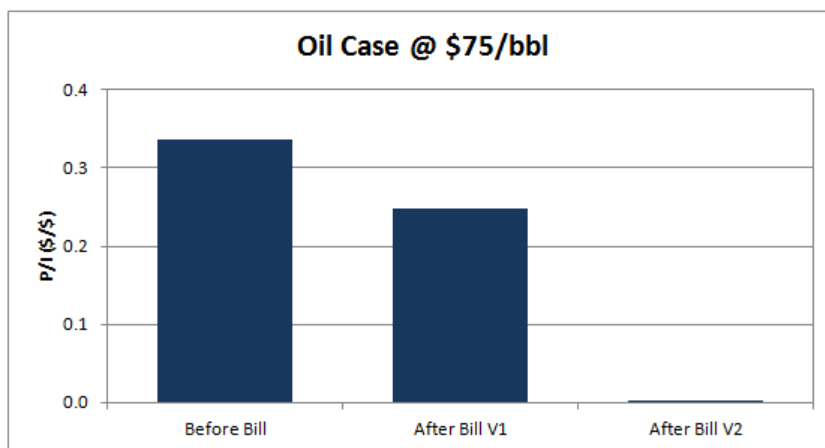


Figure 21: Oil Case - Reduction in P/I due to changes in the Bill

As, with NPV and IRR, the P/I in figure 23 and 24 points out the decline in the attractiveness of the opportunity from “Before Bill” to “After Bill V1” and again to “After Bill V2”. In the oil case the P/I declines from \$0.34/\$ to \$0.25/\$ to \$0.00/\$.

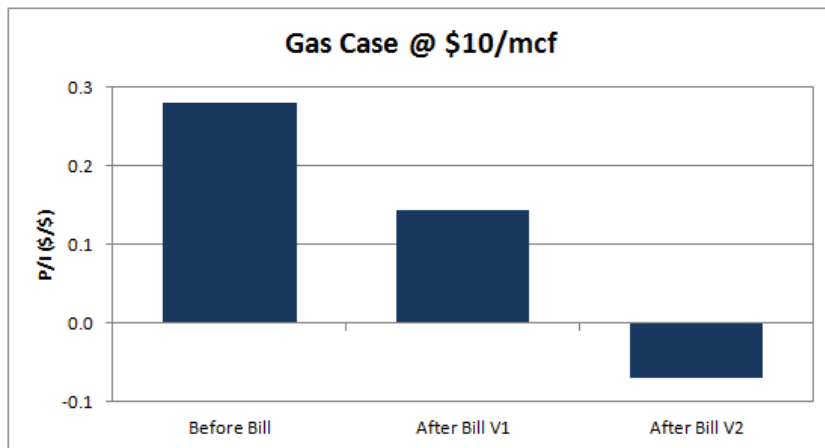


Figure 22: Gas Case - Reduction in P/I due to changes in the Bill

In the gas case the P/I declines from \$0.28/\$ to \$0.14/\$ to -\$0.07/\$.

#### 4. Payback Period

This is the number of years, counting from the start of the development phase, required to receive accumulated net revenues equal to the investment.

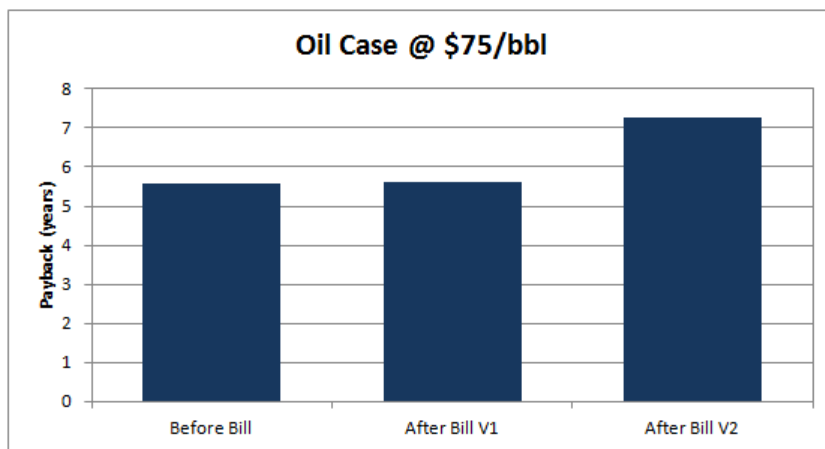


Figure 23: Oil Case – Payback (from start of Development phase)

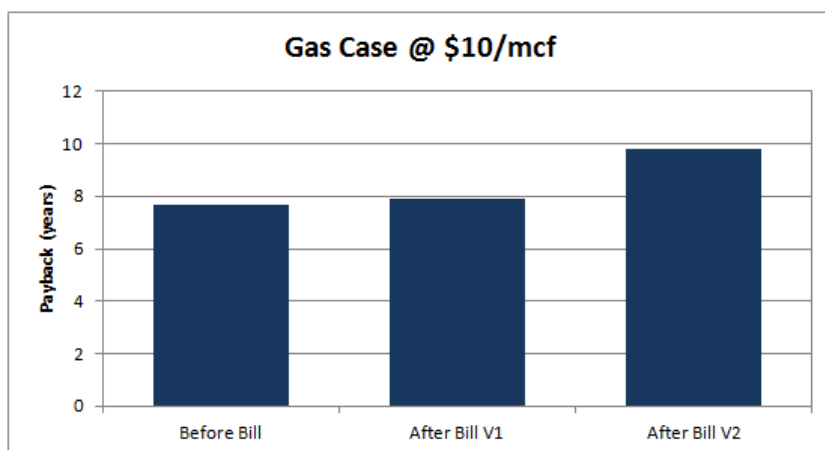


Figure 24: Gas Case – Payback (from start of Development phase)

In figure 25 and 26, the payback years are very similar for “Before Bill” and “After Bill V1”. This is because; the numbers are unaffected by the BEE equity (this is an undiscounted metric and it is assumed that the BEE partner repays past costs in full), the National Oil Company pay for their own expenditures from development phase onwards in both the “Before Bill” and “After Bill V1” scenarios and the numbers aren’t affected by the portion of equity held by the contractor (only affected by the carries and carry repayments). The “After Bill V2” scenario has a longer payback period because the National Oil Company is carried for all expenditures.

##### 5. Minimum Commercial Field Size (MCFS)

This is the minimum field size that warrants commercial development with a 10% NPV of zero.

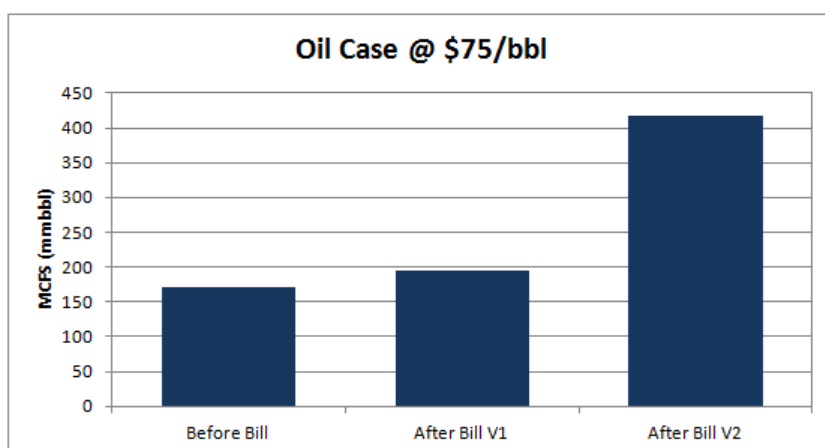


Figure 25: Oil Case - Increase in MCFS due to changes in the Bill

In figure 25, the MCFS moves from 171mmbbl “Before Bill”, to 195mmbbl “After Bill V1”, to 418mmbbl “After Bill V2”. The impact of the interpretation of the 20% free carry of the National Oil Company equity is clearly displayed between the MCFS of “After Bill V1” and “After Bill V2”. The field sizes required for a zero NPV more than doubles between the two scenarios.

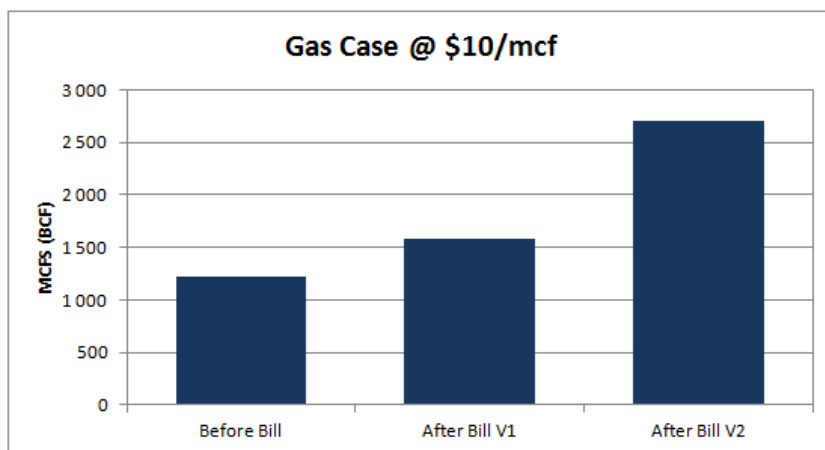


Figure 26: Gas Case - Increase in MCFS due to changes in the Bill

The same trend is apparent in the gas case. The MCFS moves from 1223 BCF “Before Bill”, to 1585 BCF “After Bill V1” to 2701 BCF “After Bill V2”. The effect of larger MCFS’s is that there are very few prospects that are big enough to be drilled and if discoveries are made, anything smaller than the MCFS could not be developed. This represents a massive hurdle to investors in the oil and gas industry.

## 6. Breakeven Price

The breakeven price is the oil or gas price that results in a 10%NPV of zero.

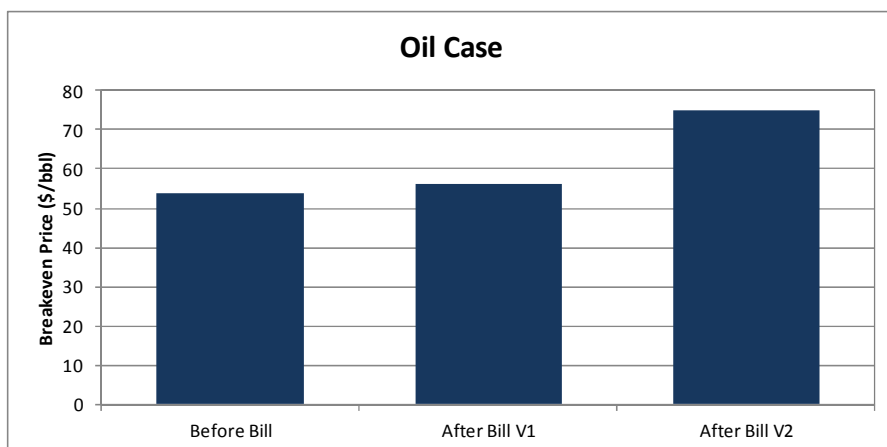


Figure 27: Oil Case - Increase in Breakeven Price due to changes in the Bill



The breakeven oil price moves from \$53.65/bbl in “Before Bill” to \$74.80/bbl in “After Bill V2”. In the current oil price environment of \$50/bbl, none of the scenarios would warrant investment, but there is a general expectation that the oil price will have increased again by the time production from these scenarios commences.

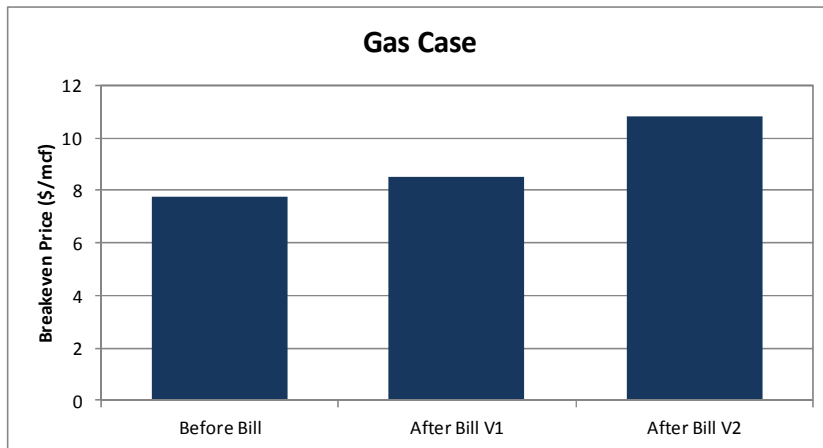


Figure 28: Gas Case - Increase in Breakeven Price due to changes in the Bill

The breakeven gas price moves from \$7.76/mcf in “Before Bill” to \$10.81/mcf in “After Bill V2”. A gas discovery of this size generally doesn’t warrant exportation, and it is likely to be used for power generation in the local market. The price the market can absorb is directly dependent on the price of competing input materials like coal.

#### 7. Expected Monetary Value

To calculate the expected monetary value, the NPV of the mean scenario multiplied by the geological probability of finding hydrocarbons must be added to the discounted cost of failure multiplied by the probability of drilling a dry hole.

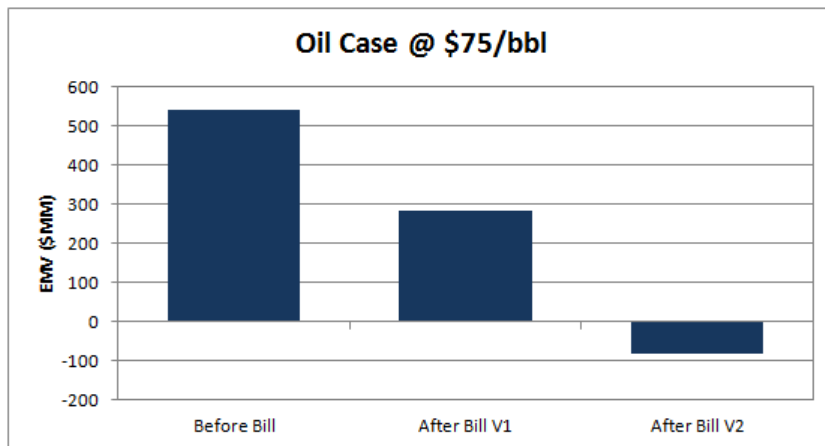


Figure 29: Oil Case – Decrease in EMV due to changes in the Bill

The EMV of the oil case decreases from \$540MM in “Before Bill” to \$285MM in “After Bill V1” to -\$83MM in “After Bill V2”. The change in EMV is pronounced because of the Contractor’s high equity position (100% of the exploration costs) in the exploration phase when all the cost of failure expenses are incurred.

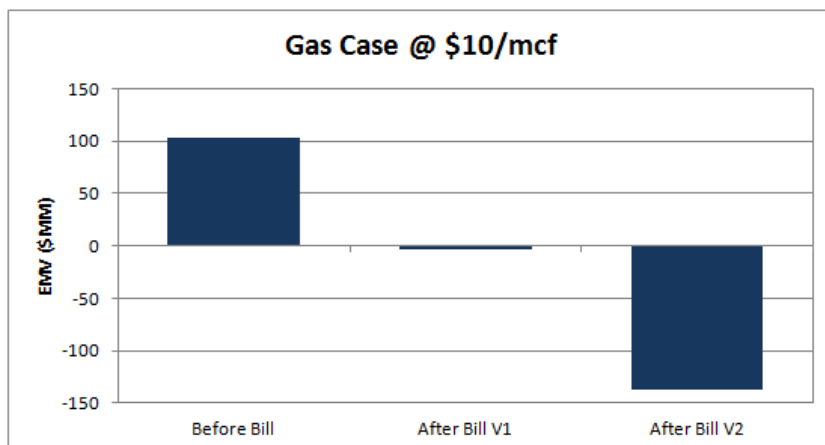


Figure 30: Gas Case – Decrease in EMV due to changes in the Bill

The EMV of the gas case decreases from \$103MM in “Before Bill”, to -\$3MM in “After Bill V1”, to -\$137MM in “After Bill V2”.

In Figure 33, the probability of commercial failure is plotted against the EMV. The probability of commercial failure takes the possible resources distribution and the MCFS into consideration and indicates the probability of making a discovery smaller than the MCFS.

A prospect’s position in the graph can be used to classify it into risk and reward categories. The bottom right hand outcomes are obviously the most favourable for an investor. The “Oil

Case – Before Bill”, “Gas Case – Before Bill” and “Oil Case – After Bill V1” falls within this category of low risk / high reward. The top left hand outcomes do not warrant investment as they effectively erode value and “Gas Case – After Bill V2” and “Oil Case – After Bill V2” fall within this category of high risk / low (negative) reward.

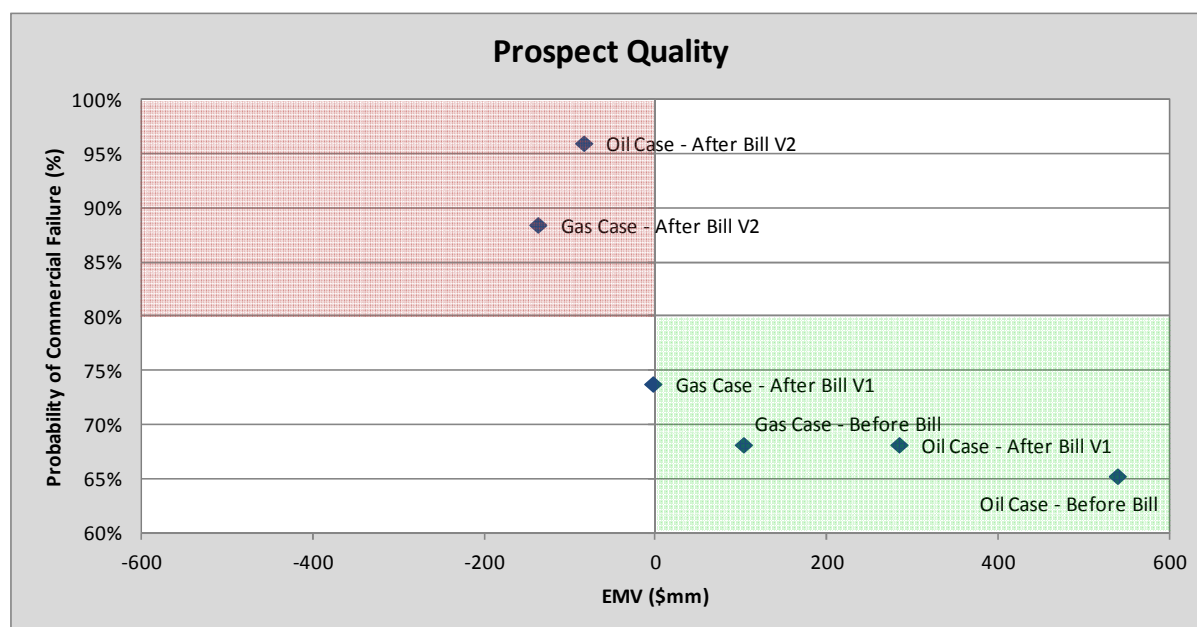


Figure 31: Prospect Quality

The final two tables summarise the results in this section and provide the full picture of the impact the Mineral and Petroleum Resources Development Amendment Bill has.

OIL CASE @ \$75/bbl	Before Bill	After Bill V1	After Bill V2
Gross Volume	422bbl	422bbl	422bbl
10.0% NPV	\$1 655MM	\$982MM	\$11MM
10% NPV/BBL	\$5.1/bbl	\$4.5/bbl	\$0.1/bbl
IRR	19.5%	17.3%	10.1%
10% P/I	\$0.34/\$	\$0.25/\$	\$0.00/\$
Payback	5.6 years	5.6 years	7.3 years
MCFS	171bbl	195bbl	418bbl
BreakevenPrice	\$53.65/bbl	\$56.11/bbl	\$74.80/bbl
EMV	\$540MM	\$285MM	-\$83MM
Probability of Commercial Failure	65.3%	68.2%	96.0%

Table 9: Oil Case - Result Summary

GAS CASE @ \$10/mcf	Before Bill	After Bill V1	After Bill V2
Gross Volume	2 334bcf	2 334bcf	2 334bcf
10.0% NPV	\$503MM	\$224MM	-\$130MM
10% NPV/BOE	\$1.6/boe	\$1.1/boe	-\$0.6/boe
IRR	13.8%	12.1%	8.9%
10% P/I	\$0.28/\$	\$0.14/\$	-\$0.07/\$
Payback	7.7 years	7.9 years	9.8 years
MCFS	1 223bcf	1 585bcf	2 701bcf
BreakevenPrice	\$7.76/mcf	\$8.53/mcf	\$10.81/mcf
EMV	\$103MM	-\$3MM	-\$137MM
Probability of Commercial Failure	68.2%	73.8%	88.5%

Table 10: Gas Case - Result Summary

### 4.3 Summary of Results

It is clear from the results that the Mineral and Petroleum Resources Development Amendment Bill has a material impact on the commerciality of exploration opportunities in the upstream oil and gas industry. In the fiscal comparison, South Africa's Total State Take moves from just below 50% without the Bill, to just below 70% or even 80%, depending on the interpretation of the Bill. When comparing the cumulative cash flows of the contractor (based on the hypothetical development scenario), it becomes apparent that the contractor's exposure during the exploration phase is the same in all three scenarios evaluated ("before Bill", "after Bill V1" and "after Bill V2"), even though the cumulative cash flow at the end of the project is about double in the "before Bill" scenario when compared to the "after Bill V2" scenario. This is a noticeable change in the risk / reward ratio, with the contractor taking all the exploration risk, but receiving less of the revenue (only 54%) post Bill.

Key economic indicators will be an important focus for management when deciding whether or not to invest in opportunities in South Africa's upstream oil and gas sector. The profitability of these opportunities and the number of them that warrant investment will be markedly reduced under the conditions of the new Bill. The hypothetical development scenarios are very good investment opportunities "before Bill" but their value is eroded to such a point in the "after Bill" scenario that they do not merit investment.

## 5. CONCLUSION

If wisely managed, a large oil or gas discovery could significantly alter the economic fortunes of a country. Investment in the industry should therefore be encouraged by offering stable and lenient fiscal terms, while still ensuring the Government, National Oil Company and BEE Partners receive a fair share of revenue/profits. Even though South Africa has limited reserves, a lot of exploration activity is taking place under the current legal and fiscal framework, because it is currently a globally competitive fiscal regime.

The Mineral and Petroleum Resources Development Amendment Bill contains a number of substantive changes that have a major negative impact on the contractor's exposure during exploration and the profitability of potential discoveries. Some of the changes aren't clearly defined so it makes the measurement of their impact challenging. If the Bill is implemented, it will negatively influence the attractiveness of South Africa as a location for upstream oil and gas investments. The rapid fall in the oil price from mid 2014 to date will only accentuate the competitive pressures on countries and the relevance of attractive fiscal terms will become more important for countries in order to attract exploration activity.

The consequence of the changes in the participation levels of the National Oil Company and BEE partners is quantified in the results section. When ranked on Total State Take, the country moves from having some of the best fiscal terms in Africa without the new Bill, to a position where the fiscal terms can be described as average or onerous, depending on the interpretation of the "free carried interest" of the National Oil Company. Countries which offer terms which are perceived by the industry to be 'in balance' with their respective oil and gas prospectivity, are likely to attract relatively high levels of industry investment and activity. The limited amount of gas and gas reserves in South Africa therefore call for favourable fiscal terms to attract investment.

The increase in National Oil Company equity from 10% to 20%, with the carry changing from exploration carry to "free carried interest", and the increase in BEE equity from 10% to 26% is severe. This level of State Participation is not industry practice and it will increase the contractors' upfront exposure in the high risk exploration phase, where they are likely to pay 100% of the costs but only receive 54% of future revenue and possibly pay for all of the National Oil Company's project expenses. This level of State participation is extremely high by world standards even without the element of a "free" carry.

The results of the hypothetical field developments showcase the impact on the economic worth of projects. In the specific scenario evaluated, the opportunity has very positive Economic indicators

without the changes from the new Bill. If the 20% National Oil Company interest is only carried for exploration, the opportunity is less attractive but still viable and if the 20% National Oil Company interest is carried for all costs the opportunity wouldn't warrant investment.

The concerns President Jacob Zuma has about the constitutionality of the Bill, and his refusal to sign the Bill in its current format is well founded. While there is likely to be scope to improve the country's Total State Take to some degree, the mechanisms selected to do this need to be carefully understood and their impact on investment in the industry needs to be taken into consideration. Fiscal adjustments could also be phased in over time, depending on the success or lack thereof that the industry enjoys over the next decade.

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